January 13, 2017

Via electronic filling and postal mail

Carlotta Stauffer
Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Docket numbers 160186-EI, 160170-EI

Dear Ms. Stauffer:

Enclosed for filing on Sierra Club's behalf in the above dockets please find:

1. Direct Testimony and Exhibits of Sierra Club's Witnesses Mosenthal and Loiter; and

2. Declarations of Sierra Club's Standing Witnesses Kanfer, Fashho, Adams, Chamblin, Rothstein, W. DuBois, and M. DuBois.

Sierra Club is filing three (3) documents representing the components of the enumerated items via the Commission's Electronic Web Filing Form. Should you or your staff have any questions regarding this filing, please contact me.

Sincerely,

/s/
Diana A. Csank
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Sierra Club
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Qualified Representative for Sierra Club

Enc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served electronically on this 13th day of January, 2017 on:

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This 13th day of January, 2017.

/s/ Diana A. Csank

Diana A. Csank
Qualified Representative for Sierra Club

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Gulf Power Company	Docket No. 160186
In re: Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals and Plant Smith Units 1 and 2 regulatory asset amortization, by Gulf Power Company	Docket No. 160170 Filed: January 13, 2017

Prepared Direct Testimony of
Philip H. Mosenthal

On Behalf of
Sierra Club

January 13, 2017

Table of Contents

Table of Figures

Exhibit List

Exhibit PHM-1	Resume of Philip H. Mosenthal
Exhibit PHM -2	OPC Interrogatory No. 130
Exhibit PHM -3	Staff Interrogatory No. 64
Exhibit PHM -4	OPC Interrogatory 174
Exhibit PHM -5	*Sierra Club, Inc. et. al v. Richard E. Dunn*, CV #: 2017CV284719, Petition for Writ of Mandamus (Jan. 12, 2017)
Exhibit PHM -6	Marcy, Cara. "Renewable generation capacity expected to account for most 2016 capacity additions." U.S. Energy Information Administration, 10 Jan. 2017, www.eia.gov/todayinenergy/detail.php?id=29492.
Exhibit PHM -7	Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United State, Authors Mark Bolinger and Joachim Seel, Lawrence Berkeley National Laboratory, September 2015
Exhibit PHM-8	Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United State, Authors Mark Bolinger and Joachim Seel, Lawrence Berkeley National Laboratory, August 2016
Exhibit PHM-9	2015 Wind Technologies Market Report, Authors Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory, August 2016
Exhibit PHM -10	Georgia Power Company Stipulation

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. Philip H. Mosenthal, Optimal Energy, Inc., 10600 Route 116, Hinesburg, VT 05461.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. By whom are you employed and in what capacity?

A. I am the founding partner in Optimal Energy, Inc., a consultancy specializing in utility planning and energy efficiency. Optimal Energy advises numerous parties including utilities, non-utility program administrators, governments, and consumer and environmental groups.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes. I testified in Commission proceedings to review numeric conservation goals, Docket Nos. 080407–080413.

Q. Have you testified elsewhere on long-term resource planning issues?

A. Yes. I have testified before numerous states. This includes testimony related to integrated resource planning and the prudency of building or procuring new electric resources in Illinois, Indiana, Missouri, Vermont, and Virginia, the Texas legislature, and the U.S. Nuclear Regulatory Commission.

Q. Please describe your educational background and professional experience.

A. I have 30 years of experience in utility resource planning, during which I have focused on the costs and benefits of various resources and the opportunities for demand-side resources to be considered on an equal footing with supply-side resources. This has included leading or participating in numerous studies to assess the quantity and economic value of efficiency and renewable resources as potential alternatives to conventional supply-side options for short and long range utility integrated resource planning. I have been involved in studies in numerous jurisdictions throughout the U.S. and Canada, as well as work in Europe and Asia.

Additionally, I have addressed issues of utility cost recovery, lost revenue, decoupling, and the creation of shareholder financial incentives to ensure that utilities have appropriate incentives to consider all potential energy resources on an equal footing and to pursue the prudent, least-cost solutions for customers. I have also developed numerous utility efficiency plans, and designed and evaluated utility and non-utility programs.

I have a *B.A.* in Architecture and an *M.S.* in Energy Management and Policy, both from the University of Pennsylvania. My resume is attached as Exhibit PHM-1.

Q. What is the purpose of your testimony in this proceeding?

A. I address the proposal by Gulf Power Company (Gulf or the Company) to shift its 25% ownership interest in Plant Scherer Unit 3 (Scherer 3) into rate base. The proposal includes shifting the costs associated with Scherer 3 onto Gulf's native load retail customers (customers), as well as allocating Scherer 3 capacity to customers. My testimony assesses the prudency of that proposal and whether it meets the Commission's least cost planning criteria.

Q. What are your overall conclusions?

A. Gulf's proposal is not prudent because it would impose a significant financial burden on retail customers in exchange for speculative benefits. Evidently, other market participants have rejected Scherer 3 in favor of other options. My analysis confirms that there are abundant, low-cost, and low-risk options in the market available to Gulf. Yet the Company presented no quantitative analysis of its proposal relative to these alternatives; instead, Gulf asks the Commission to rely on the Company's beliefs about alternatives that it acknowledges it never evaluated with any quantitative rigor.

Q. What sources have your relied on in your assessment of Scherer 3?

A. I have focused on Gulf's filings related to Scherer 3 in this proceeding, including its petition, direct testimony and exhibits, and discovery responses. I also reviewed Gulf's recent ten-year site plan filings as well as Commission Order No. PSC-16-0535-FOF-EI, which deferred environmental compliance cost recovery related to Scherer pending the resolution of this proceeding. Finally, I have drawn on several recent market studies and state electric utility regulatory proceedings pertaining to resource planning and procurement. When relying on various sources, I have referenced such sources in my testimony and/or attached these sources as exhibits.

II. FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings regarding Scherer 3 in this case.

A. Including the costs associated with Scherer 3 in rate base, and allocating its capacity to Gulf's retail customers is neither prudent nor consistent with least cost planning, for the following reasons:

1. Gulf itself projects that there is no need for Scherer 3 capacity until 2023, and even then the projected capacity need is not reliable.

2. Assuming a capacity need beginning in 2023, it is premature to burden customers with the costs and risks of an aging coal plant now, when they will see no concrete benefits from Scherer 3 for seven years or more, and there is a significant risk that the costs will outweigh any long-term benefits.

3. Approval of Gulf's proposal would result in an undiversified resource portfolio that is dangerously dependent on coal, exposing customers to

unnecessary risk, and missing opportunities that would improve diversity and offer a better hedge value.

4. Gulf has not evaluated alternative options to meet its projected 2023 reliability need, nor shown that Scherer 3 is a least cost option, and there is ample evidence that lower-cost and lower-risk options are available in today's market and more than likely in the 2023 market as well.

Q. What are your recommendations to this Commission?

A. As I will explain further, the Commission should deny Gulf's proposal to add Scherer 3 to rate base in order to protect retail customers. The Commission should also reinforce that the Company is responsible for presenting sufficient information to reassure the Commission that it is planning an adequate and reliable supply of electricity at the lowest cost possible. To this end, the Company must make timely efforts, with proper Commission oversight, to evaluate and then pursue all reasonably available prudent alternatives to minimize the cost of serving its customers' needs.

III. SCHERER 3: A "MISMATCH" FOR RETAIL CUSTOMERS

Q. What is Scherer 3?

A. Scherer 3 is one of four steam units at Plant Scherer, a coal-fired power plant located about 20 miles northwest of Macon, Georgia. In 1981, Gulf purchased a

25% ownership share of Scherer 3. This is equivalent to 211 MW capacity. Scherer 3 began commercial operation in 1987.

For nearly its entire, thirty-year operating history, Gulf dedicated its portion of Scherer 3 to wholesale power contracts instead of its customers. At the time of purchase, Gulf did not have a resource capacity need, but projected that demand would grow sufficiently to require this additional capacity in the future. Gulf then entered into wholesale contracts to sell Scherer 3's available output. Gulf's forecast of load growth was overly optimistic, however, and the Company still does not have a need for this capacity to meet its reserve margins, despite some recent retirements of its other coal plants.

As the Scherer 3 wholesale contracts have begun to expire, Gulf has not been able to renew them or find new buyers, at least not at prices the Company will accept.[1] Nor has Gulf identified any viable options yet for an economic asset sale.[2]

Q. What does Gulf propose to do now with Scherer 3?

A. As witness Liu explained, Gulf is seeking authorization from the Commission to allocate all of Scherer 3's available capacity (161 MW immediately, growing to 211 MW in 2020) to retail customers, and put all outstanding, "non-clause" costs into rate base (Pages 3-4). Nevertheless, Gulf acknowledges that there is no need for

[1] *See* Gulf's Response to OPC Interrogatory No. 130, Exhibit PHM-2.
[2] *Ibid.*

Scherer 3 until 2023 at the earliest, and, as I will explain, it is unclear whether the need will in fact materialize in 2023.

Q. **When does Gulf project a potential need for the Scherer 3 capacity?**

A. Gulf anticipates a potential need for capacity in 2023, when one of its power purchase agreements (PPA) expires.[3]

Q. **Please explain whether you agree with Witness Burleson that there is a "mismatch" between Scherer 3 and the needs of retail customers.**

A. Yes, there is a stunning mismatch because Scherer 3 does not line up with customer needs—not now, in fact, perhaps never. Here, as Witness Liu explains, Gulf seeks $19.4 million in Scherer 3 costs from customers in 2017 (Page 15, lines 10-11), but they do not need any additional capacity for at least another 7 years, until 2023.[4] Furthermore, Scherer 3 would not be the best option to meet such need should it ever materialize.

Q. **You state that Gulf's projected need for new capacity in 2023 is not reliable. What do you base this on?**

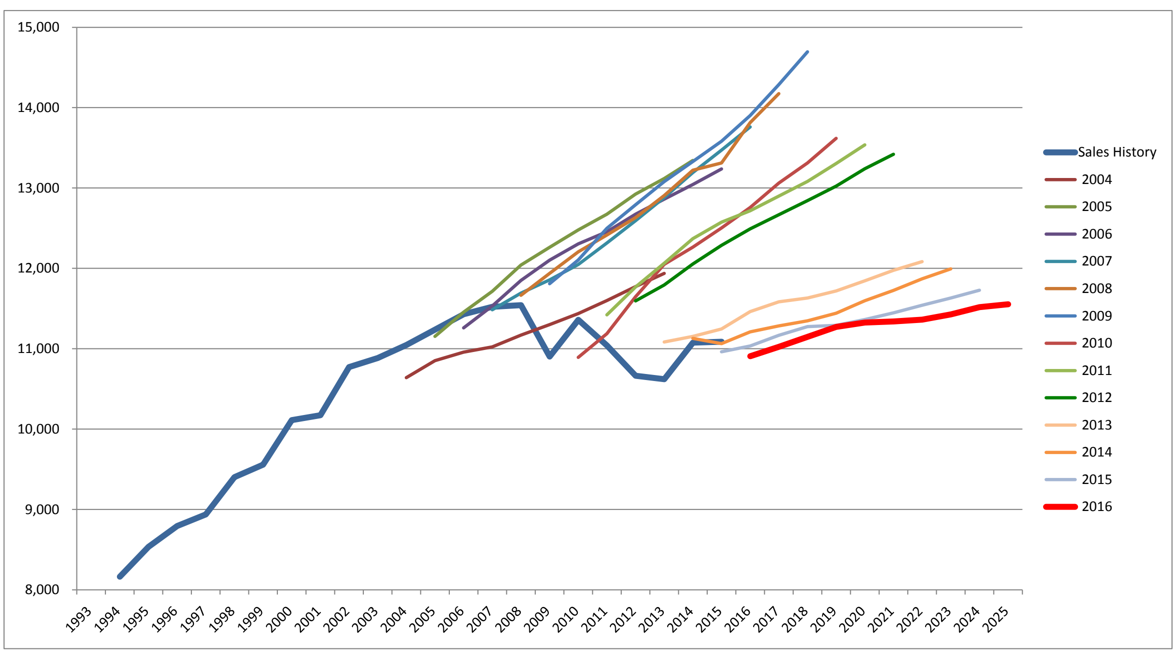
A. Gulf has a history of substantially overestimating load forecasts. For example, Witness Liu states, "Gulf's weather-normalized annual GWh sales have never reached the level that we originally projected to achieve in 2012, and sales are not

[3] Gulf's 2016 TYSP, at 52; Gulf's Response to Staff Interrogatory No. 64, Exhibit PHM-3.
[4] Exhibit PHM-3.

currently projected to reach that level in 2017" (Page 14, lines 12-15). Ms. Liu also states, "GWh sales for 2017 are forecast to be **6.3 percent below** the originally projected level for 2012" (Page 18, 12-14) [emphasis added].

Even with future load growth of approximately 1% per year – significantly more than recent history – the load in 2023 would still just barely reach the levels the Company originally projected for 2012. The figure below shows Gulf's dramatic overestimation of load growth going back to 2004.[5] Further, it depicts Gulf's failure to recognize industry trends of low load growth and the sustained impacts of efficiency and distributed generation.

Figure 1: Gulf Power Actual and Forecast Load Growth



[5] Source: Schedule 2.2 of past Gulf Ten-Year Site Plans, 2004-2016.

Q. What evidence do you have for a trend of low energy load growth?

A. There is substantial evidence of this phenomenon throughout the U.S. As an example, EIA projects U.S. retail electricity sales will grow at an average annual rate of just 0.39% from 2015-2030, substantially lower than the historic average of 1.6% from 1990-2010.[6] Excluding transportation, which is expected to grow 14% per year from adoption of electric vehicles, retail loads are projected to only grow 0.29% annually.

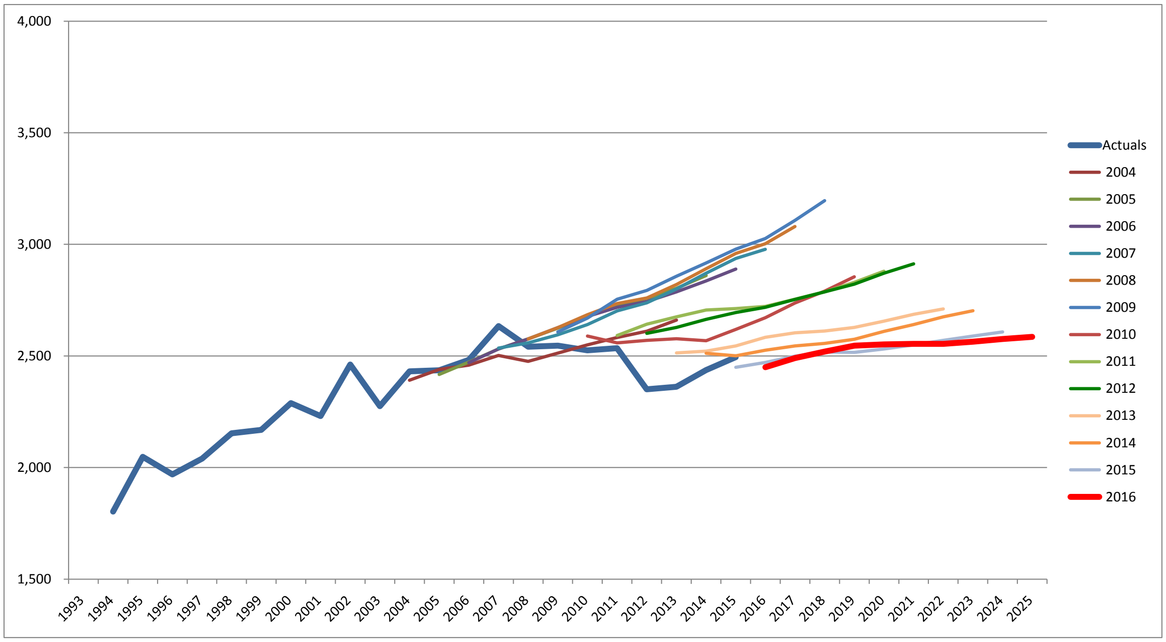
Q. Isn't Gulf's justification for the 2023 need based on peak demand and the expiration of an existing PPA, rather than energy load growth?

A. Yes, but the persistent bias in Gulf's above referenced projections calls into question the accuracy of Gulf's forecasts in general, and especially the Company's ability to accurately forecast the timing of a need so far in advance. In fact, as Figure 2 below shows, Gulf appears to suffer from the same persistent bias when it comes to summer peak demand, and has not experienced any actual load growth since 2007.[7]

[6] https://goo.gl/2EEapV.

[7] Source: Schedule 3.1 from past Gulf Ten Year Site Plans.

Figure 2: Gulf Power Actual and Projected Summer Peak Demand



Furthermore, as shown in Gulf's response to Staff interrogatories, its estimated 211 MW peak contribution in 2023 from Scherer represents **only 8%** of its projected 2023 summer peak.[8] As I discuss, this is well within the range that can be captured solely through efficiency and demand response (DR) programs, and certainly could be made up with a mix of efficiency, DR, distributed generation (DG) and future PPAs. Gulf also has ample time to procure these potential resources by 2023, as I will explain.

Q. Assuming for the moment that the capacity driven reliability need does exist in 2023, is Scherer a logical resource to fill that need?

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[8] Exhibit PHM-4.

A. Absolutely not. As Witness Burleson notes, Scherer 3 is a coal plant with a low variable cost (Page 20, lines 25-25). Such plants generally serve as baseload plants, and Gulf has indicated that Scherer is no exception.[9]

Gulf has also acknowledged that a peaking unit is more likely what its customers would need next. Thus, Gulf plans to build a 654 MW gas combustion turbine to go online in 2023. Such turbines are designed to serve as peaking units. This makes them better able than Scherer 3 to serve customers' peak demand for electricity.

In short, you can once again see the mismatch between Scherer 3 and customer needs. It makes no sense to burden customers with a new, unneeded baseload coal plant to meet a possible future peak capacity reliability need.

Q. Could it nonetheless be prudent for customers to start funding Scherer 3 now to preserve the capacity for the future?

A. No. To be prudent, the expense has to be "used and useful" to customers. This is a core requirement in Florida, as in so many other states, to protect customers from bearing the risk of utility expenses that may never confer concrete benefits to the customers.

[9] Exhibit PHM-2 (stating Gulf only responded to RFPs to sell Scherer on the wholesale market for "base load" needs).

As discussed, Scherer 3 does not meet the used and useful requirement because customers do not need this coal plant now. Further, they may never need it. Given Gulf's faulty forecasting, its substantial overestimation of loads, and industry trends of low to no load growth, asking customers to begin paying now for a speculative, possible need in the future is unreasonable. This would be true even if Scherer 3 could somehow become a least-cost option in the future, a position that Gulf has avoided taking and could not possibly justify under current market conditions, as I will explain.

Second, even assuming a 2023 capacity need, there is no justification to impose on ratepayers this financial burden now. There are many other options that Gulf can rapidly deploy in the future, and which are likely to be less costly and require far less lead-time. As an example, one option could be for Gulf to renew the expiring Shell power purchase agreement (PPA), which as noted is mainly driving the purported 2023 need. Gulf is yet to assess this as an alternative.[10]

Third, Gulf acknowledges that the ultimate, long-term costs of Scherer 3 are uncertain and could be significantly higher in the future due to new and evolving environmental compliance requirements and other risks yet-to-be quantified or disclosed by the Company.[11] As a result, under Gulf's proposal, ratepayers would

[10] Gulf's Response to OPC Interrogatory No. 174, Exhibit PHM-4.
[11] Gulf's 2016 TYSP, at 53-65.

be committed to paying for an aging coal plant that is unneeded, may never be needed, and imposes new and unnecessary risks.

Q. But didn't Witness Burroughs say that Scherer 3 is "fully controlled" in terms of environmental compliance?

A. He could have chosen his words more carefully. It is my understanding that Scherer 3 does have some modern air pollution controls, but still faces additional costs and risks, for example, based on a recent complaint filed in Georgia state court concerning the water pollution control requirements for several coal plants, including Scherer.[12]

Further, in its 2016 Ten-Year Site Plan, Gulf acknowledges that it does not know the "ultimate financial and operational impact" of various regulations that are still in flux.[13] Keep in mind, whatever the Company has already sunk into Scherer Unit 3 does not negate the risk and cost of such potential additional regulatory compliance.

IV. HEDGING AND DIVERSIFICATION

Q. Is there any evidence that pursuing PPAs could provide Gulf with greater flexibility and potentially diminish risks?

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[12] *Sierra Club, Inc. et. al v. Richard E. Dunn*, CV #: 2017CV284719, Petition for Writ of Mandamus (Jan. 12, 2017), Exhibit PHM-5.

[13] See generally Gulf's 2016 TYSP, Environmental Compliance Section, at 53-65.

A. Yes. Signing long or short term PPAs can lock in future prices now and provide a significant hedge against future risks, including fuel price volatility and evolving regulatory requirements for coal and carbon. Gulf evidently agrees, as "this strategy of supplementing Gulf's development of long-term capacity resources with shorter-term power purchase has proven to be effective over the years."[14] Gulf also notes, "longer-term power purchases from the market" may "supply flexibility and reduced commitment risk during periods in which environmental regulations (with considerable economic impacts) and legislative initiatives focusing on generation additions are in various stages of development."[15]

Q. Do you have other evidence that PPAs can be an effective hedge against future risks such as price volatility or environmental risk?

A. Yes. First, it is common practice for electric utilities to lock in contract prices as a hedge against future financial risks.

Second, renewable energy PPAs are now often the cheapest and most prevalent new generation resource, as I discuss below. These PPAs also have no fuel costs, and thus completely hedge against volatile fuel prices. The U.S. Department of Energy has found, "[s]olar and wind generation significantly reduces the exposure

[14] Gulf's 2016 TYSP, at 51.
[15] *Id.* at 67.

of electricity costs to natural gas price uncertainty in fossil-based generation portfolios on a multi-year to multi-decade time horizon."[16]

Third, the Commission for Environmental Cooperation (CEC), which is the collaborative between the U.S., Canada, and Mexico on advancing economic development alongside environmental protection, has also found that long-term renewable energy contracts are very attractive to utilities and their customers for their long-term hedge value. The CEC concludes that the fixed, long-term price of these contracts for terms that often exceed ten years, "offer[s] a **longer-term hedge** than many of the conventional hedging strategies, which often focus on short-term markets."[17]

Further, the CEC has emphasized the value of renewables as a hedge against regulatory compliance risks:

> Future requirements are likely to be more severe than they are today. Traditional air pollutants (SOx, NOx, mercury, particulate matter) may be more tightly regulated and new state or federal carbon regulations may be implemented. Utility-owned fossil projects and long-term power purchase agreements may be subject to these downside regulatory risks. However, renewable energy is likely to be unaffected.

[16] https://goo.gl/PAAwrR.
[17] https://goo.gl/YeiOvm.

Thus, the CEC concluded, "those utilities that consider seriously the risk of future environmental regulations will prefer new renewable energy to new fossil generation, all other things equal."[18]

Q. Doesn't witness Burleson state that Scherer 3 will also offer value in the long run by offsetting some coal plant retirements and tempering a trend in Florida toward natural gas?

A. While he does say that, his emphasis on the rest of Florida is misplaced. Gulf's own resource mix is the most relevant concern in this proceeding where the Commission sets rates in order to minimize the costs and risks to Gulf's captive customers. As Staff demonstrated in their review of Gulf's Ten Year Site Plan, Gulf projects a dramatic shift away from its current mix with 40.6% coal generation to a dangerously undiversified portfolio that relies on coal for 84.9% of generation.[19] See Figure 3 below.

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[18] *Id* at 34.

[19] Florida PSC, *Review of the 2016 Ten Year Site Plans of Florida's Electric Utilities,* November 2016, at 69.

Figure 3: Gulf Power Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	7,787	**64.9%**	1,828	**14.5%**
Coal	4,876	**40.6%**	10,687	**84.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable[6]	235	**2.0%**	1,091	**8.7%**
Interchange	-903	-7.5%	-1,023	**-8.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**11,996**		**12,583**	

Q. How does this compare with industry trends?

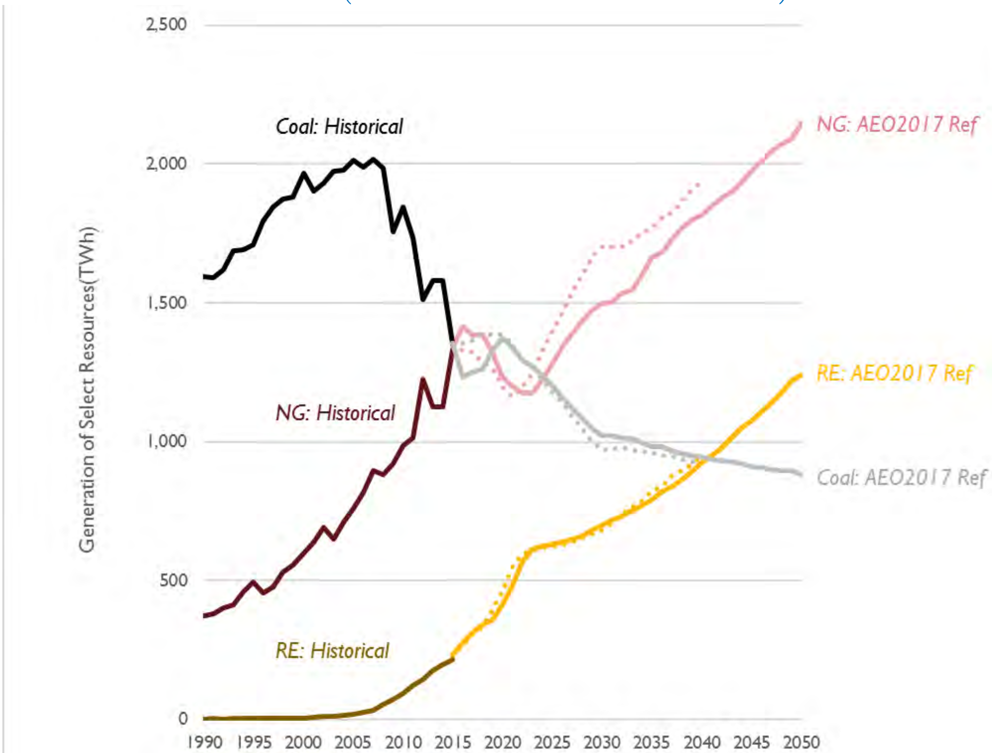
A. Gulf is going in exactly the opposite direction as the industry. Utilities are deliberately selecting strategies to avoid over-reliance on any single fuel source, much less coal. It is a well-known fact that utilities across the country are rapidly retiring and divesting their coal generation. The EIA expects this trend to continue until 2050, as shown in Figure 4 below.

Q. Is this national trend occurring in the Southeast as well?

A. Yes. EIA notes, "[i]n the Southeast, coal consumption in Georgia, North Carolina, and Alabama in 2015 was half the level it was in 2007."[20] Quite simply, Gulf's heavy reliance on coal would result in a much less diverse resource mix and represents a dangerous outlier in the region.

[20] https://goo.gl/h6wQuF.

Figure 4. Comparison of electricity generation from coal, natural gas, and renewables in the AEO 2017 Reference case (AEO2017 Ref) relative to the same cases in AEO 2016 (shown on this chart in dotted lines)[21]



Q. Besides the coal divestment trend, what about new generation?

A. The industry has turned sharply away from coal towards renewables, as the dominant source of new generation. While the EIA is still finalizing the 2016 data, it expects that, "[f]or the third consecutive year, more than half of [the country's new generation] additions are renewable technologies, especially wind and solar."[22]

[21] Note: In this figure, "renewables" includes all generation from wind and solar. Generation from hydro, geothermal, and biomass is excluded.

[22] Marcy, Cara. "Renewable generation capacity expected to account for most 2016 capacity additions." U.S. Energy Information Administration, 10 Jan. 2017, https://goo.gl/Z5x1ao, Exhibit PHM-6.

This trend is expected to continue, if not accelerate. The U.S. production tax credit for wind and the solar investment tax credit were extended in 2015 and will continue, although at declining levels, until 2020 (wind) and 2022 (solar).[23] With the projected further cost reductions and performance improvements of renewable technologies, today's renewable energy boom will very likely grow in the future.

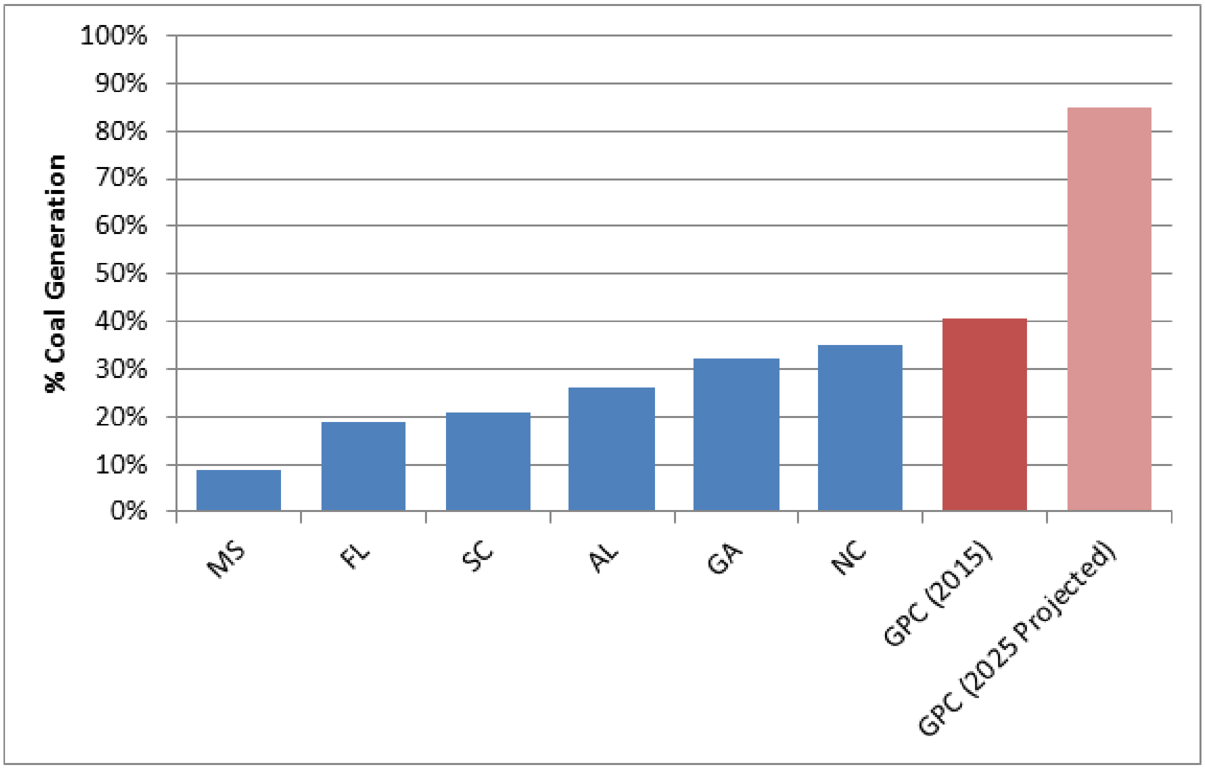
Q. How does Gulf's coal dependence compare to its peers in the region?

A. It is a clear outlier. The figure below shows installed coal capacity of states in the Southeast U.S., compared to Gulf.. Gulf is already higher than any of state, and significantly higher than Florida. What is even more concerning is that its projected coal dependence by 2025 would be an extreme outlier and counter to industry trends.[24] .

Figure 5. Percent Coal Generation, by State and Actual and Forecast for Gulf Power

[23] *Id.*

[24] Source: http://www.eia.gov/state/ Net Electricity Generation by Source, September 2016.



Q. Why is Gulf's increased coal dependence risky?

A. It is common practice with any asset portfolio to include a diverse mix of assets to hedge against any particular asset becoming uneconomic, non-productive, or otherwise a liability. Therefore, having 85% of any single asset type presents significant risk if that asset becomes uneconomic or no longer viable. This is one of the drivers of the significant coal retirements that have been occurring throughout the country. Not only is new generation of coal generally no longer competitive with gas plants or utility scale renewables, but concerns about climate change clearly make dependence on the most carbon-heavy option especially risky. As noted, uncertain environmental compliance requirements and fuel price volatility pose additional financial risk, which can be hedged with renewables and efficiency.

The Tennessee Valley Authority explicitly notes this in its 2015 findings on financial risks: "Risks are minimized by maintaining a diverse portfolio and not over-emphasizing any specific resource type." Further, "[m]aintaining the diversity of TVA's energy resources is fundamental to our ability to provide low-cost, reliable and clean electric power"[25] Consistent with these findings, TVA plans further coal retirements and no new coal generation additions through at least 2033.[26]

V. ALTERNATIVES

Q. You have stated that Gulf failed to analyze alternatives to Scherer 3, or show that it is the least-cost option. What is the basis for your statement?

A. Gulf itself makes this perfectly clear in response to discovery. Public Counsel asked what analysis of alternatives Gulf has done to assess whether Scherer 3 is a least-cost resource, including any economic or risk assessments. Gulf responded, it "has not performed, nor had performed on its behalf, an analysis to evaluate

[25] https://goo.gl/ZljjYt.
[26] *Id.*

utilizing Gulf's ownership share of Scherer Unit 3 to serve retail customers post-2015 versus other alternatives." [27]

This is an unacceptable omission. It leaves the Commission with absolutely no evidence that the Company made a timely effort to investigate and pursue every reasonably available prudent action to minimize its cost of service. Furthermore, since Gulf could not find any buyers for this power in competitive markets, Scherer likely does not represent a least costs resource.

Q. Is it common for utilities to assess alternative supply resources to determine least cost solutions to future capacity needs?

A. Yes. In my experience, best practice would include a robust scenario analysis of the various electric resources that could be deployed, their projected capital and variable costs, and the different risk factors. This analysis is even more important due to rapid changes in electric markets. To be clear, this analysis is supposed to help identify and manage uncertainty by calculating how sensitive the analysis is to common risks such as fuel price volatility, potential variation between actual and forecasted loads, and weather, economic and environmental risks.

The fact that Gulf has either failed to perform these analyses, or at least failed to provide the Commission with convincing details and results of any integrated

[27] Exhibit PHM-5.

resource planning analysis, should be justification alone to reject its Scherer 3 proposal. Quite simply, Gulf failed to show that its proposal is in the best interest of customers, and I will offer evidence that it is not.

Q. What are the various alternatives that Gulf should have analyzed?

A. Gulf should have done a comprehensive assessment of all reasonable potential sources of new capacity, generation and demand management. This should include: 1) ownership, construction and retirement options of traditional fossil fuel plants in Gulf's existing fleet; 2) a full range of renewable energy options (both utility-owned and built, PPAs and distributed generation); 3) pursuit of a range of different PPA options, including the potential renewal of its expiring Shell PPA; and 4) the full achievable potential of energy efficiency and demand response resources.

Q. Is it likely that one or more of these alternatives are a lower-cost resource?

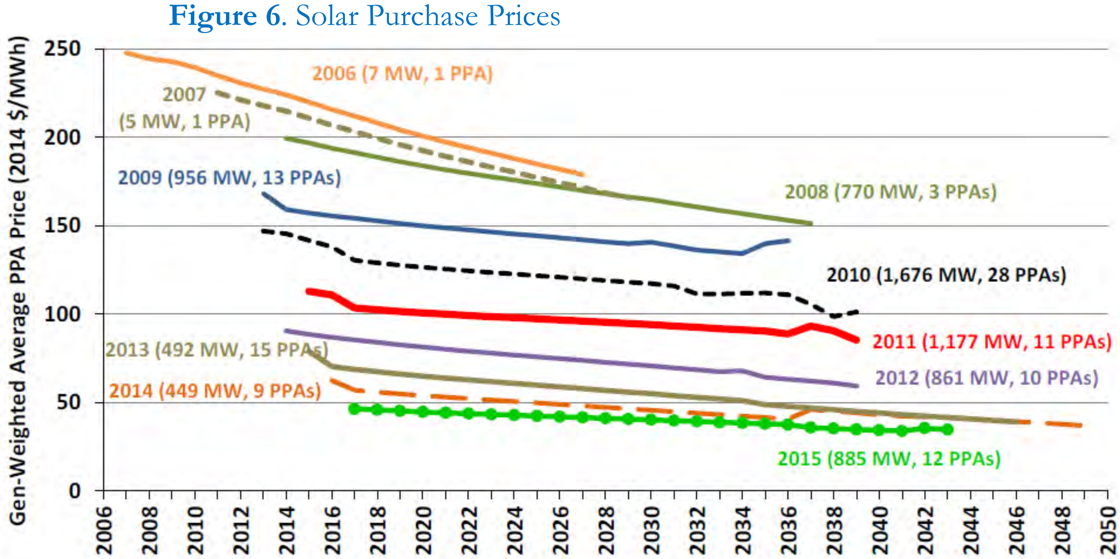
A. Yes. There is much evidence that such alternatives are generally less costly and less risky than a coal plant. For example, energy efficiency and demand response are generally only a fraction of the cost of traditional supply-side options and recent cost reduction in renewable energy have now made it the majority of new generation investments in the U.S.

Q. What evidence do you have that non-coal PPAs are available as a lower-cost alternative?

A. While I will describe some specific data on PPAs that are relevant, the most obvious evidence is the fact that Gulf has been unable to find buyers for Scherer 3 generation through long-term wholesale contracts. Nor has the Company identified any viable asset sale opportunities.[28] If Scherer 3 does not represent a good value for power purchases or investors, the same is very likely true for Gulf's customers.

In terms of recent data on already executed PPAs, the U.S. Department of Energy has documented the dramatic decreases in solar PPA prices in the last 10 years. The figure below shows dramatic decreases in solar PPAs over recent years, with levelized average generation weighted prices below $50/MWh now and projected to continue to decline.[29]

Figure 6. Solar Purchase Prices

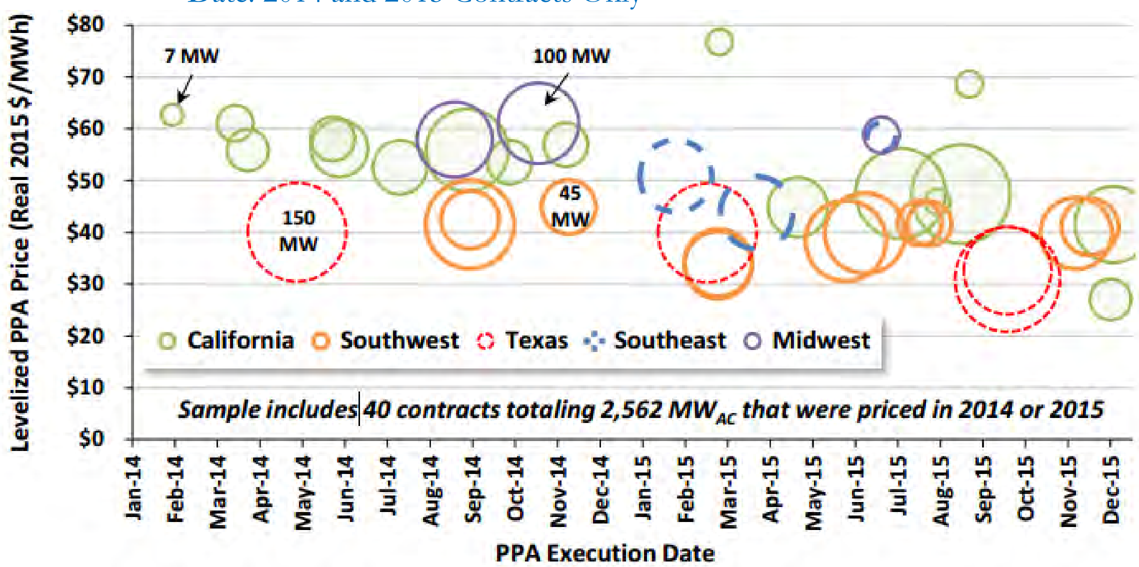


[28] Exhibit PHM-2.

[29] Figure 17, Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United State, Authors Mark Bolinger and Joachim Seel, Lawrence Berkeley National Laboratory, September 2015, Exhibit PHM-7.

While solar PPA costs have come down considerably nationally, the figure below shows that two solar PPAs of between 50 and 100 MW each were signed in the Southeast region in just the past two years at prices comparable to regions with far more experience developing utility-scale solar resources.[30]

Figure 7. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2014 and 2015 Contracts Only

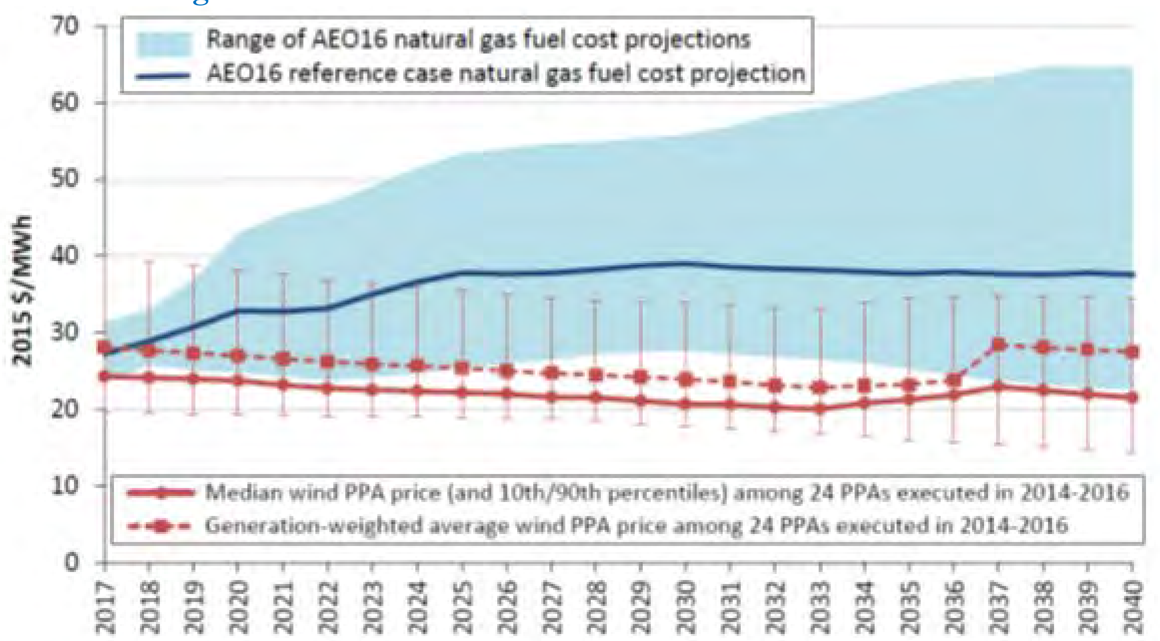


Q. Besides solar PPAs, do you have any data on wind PPAs?

A. Yes. A similar report on wind from the U.S. Department of Energy shows, in Figure 8 below, that median wind PPA price from contracts executed from 2014 to 2016 are roughly $25 per MWh and are consistently at or below the low end of the projected natural gas fuel cost range from now through 2040.[31]

[30] Figure 19, Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United State, Authors Mark Bolinger and Joachim Seel, Lawrence Berkeley National Laboratory, August 2016, Exhibit PHM-8.
[31] Figure 50, 2015 Wind Technologies Market Report, Authors Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory, August 2016, Exhibit PHM-9.

Figure 8. Wind Purchase Prices



Q. You discuss options for PPAs, including renewables. Can they meet capacity reliability needs?

A. Yes, so long as a diversified combination of resources is pursued. As noted, efficiency and DR alone could probably serve such needs in today's market. However, even solar can potentially meet this need by 2023. NextEra Energy, owner of Florida Power & Light Company (FPL), recently confirmed that combinations of solar plus storage will be able to not only serve as peaker plants, but likely will be the preferred solution. In 2015, NextEra Energy Chairman Jim Robo stated: "Post-2020, there may never be another peaker built in the United States – very likely you'll be just building energy storage instead."[32] In fact, FPL Witness Barrett recently testified before this Commission that in the next four years "large scale deployment" of energy storage and a "large program" of solar

[32] https://goo.gl/Z6WcyD.

are not only possible, together, they can address peak demand, save customers money, and produce other benefits.[33]

Q. Is there sufficient time for Gulf to forego dedicating Scherer 3 to its retail customers now and pursuing a PPA?

A. Yes. Gulf witness Burleson makes this clear. For example, he describes how Gulf issued a request for proposal (RFP) for PPAs in February 2006 for capacity starting in June 2009 (Page 16). It also began preparing in 2008 for a PPA RFP for capacity in 2014.[34] The current 855 MW Shell PPA that will expire in 2023 creating a potential reliability need was actually signed in March 2009 for delivery starting in November 2009.[35] Evidently, there is ample time for Gulf to solicit new PPAs, or potentially renew the Shell PPA, to meet any potential capacity shortfall seven years from now. In addition, given the continuing rapid declines in renewable energy PPA costs, it is likely that going to market now or later for a PPA could provide lower market prices than Scherer offers, while minimizing risk and creating greater flexibility. It would also prevent ratepayers from accepting a rate-based obligation today when their need is well in the future.

Q. What evidence do you have that energy efficiency or demand response could provide a lower cost alternative to Scherer 3?

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[33] Docket 160021, October 27, 2017, Hearing Transcript at 104, 113, 116–17 (Barrett), https://goo.gl/JBlbuO.
[34] *Ibid.*
[35] *Ibid.*

A. There is ample evidence that energy efficiency and demand response (collectively, "demand-side management" or "DSM") are the lowest cost resource to meet marginal energy and capacity needs. The record in the 2014 hearings on the numeric conservation goals of the utilities subject to the Florida Energy Efficiency and Conservation Act provides such evidence. Witness Sim testified that the total revenue requirement for the utility (i.e., the costs paid by ratepayers) is lower under a plan with higher energy efficiency savings.[36] Other witnesses demonstrated that energy efficiency generally costs less than half as much as conventional power plants.[37]

Turning to demand response, the experience of two large independent system operators is instructive. Both the PJM regional transmission organization (PJM) and the Independent System Operator of New England (ISO-NE) have emphasized the deployment of demand response in those regions to ensure sufficient capacity to meet expected loads. More specifically, they provide payments for capacity that are determined three years in advance of when that capacity is needed, thus giving capacity suppliers confidence that their investments will earn some financial return. In both cases, demand response participates in the market as a cost-effective means of supplying needed capacity.

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[36] Docket No. 130199, Hearing Transcript, Aug. 8, 2014, at 1492 (FPL witness Sim).

[37] *See, e.g., id.* at 1116-17 (Sierra Club witness Woolf).

The most recent results have demand response providing nearly 8 percent[38] and 6 percent[39] of ISO-NE's and PJM's capacity requirement in 2019, respectively. This demonstrates that demand response is cost-competitive with traditional supply options, and that even without added efficiency programs it could potentially replace the entire capacity shortfall covered by Scherer.

Q. Can you cite any recent examples of utilities in the region that are, as part of an IRP process, planning to pursue a greater mix of renewables, distributed generation and efficiency?

A. Yes. For example, Georgia Power—a Gulf sister company—recently entered into a stipulation on its integrated resource plan that includes commitments to procure 1.2 GW of renewable energy, including 150 MW of distributed generation, and 1,050 MW of utility scale resources. These would be primarily procured through RFPs that would include 525 MW of renewables with in service dates of 2018 and 2019—just 3 years after the stipulation signing and well before Gulf's need. It also calls for the rapid procurement of customer sited distributed generation in 2017 and 2018. This 150 MW of DG alone is approximately ¾ of the Scherer 3 capacity needed in 2023. The stipulation also calls for investment in energy efficiency and capital expenditure limits on existing coal plants.[40]

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[38] https://goo.gl/0PzLd5
[39] https://goo.gl/5v7fRj
[40] Georgia Power IRP Stipulation, Exhibit PHM-10.

Q. Gulf argues that because its share of Scherer 3 was originally purchased in 1981 with the intent of being used in the future as a dedicated retail customer resource, that alone is reason to adopt that 35 year old plan now. Can you comment on that?

A. It has been my experience, having worked in the regulated utility industry in many jurisdictions throughout the U.S. over the past three decades, that regulated electric utility commissions seek the best current evidence and judge the prudence of utility cost recovery proposals based on that evidence. This is not just a matter of custom and practice, but also common sense—to protect captive customers from undue rate increases. I can see no justification for now burdening Gulf's customers with an imprudent and non-least cost solution to future reliability needs simply because of a decision that the company made 35 years ago. Gulf took the risk and had a responsibility to mitigate it.

Q. Are you aware of any Florida precedent that might be germane to this issue?

A. Yes. In fact, Gulf witness Deason testified about it (Pages 17-18). As part of its rate case in 1989, Gulf proposed transferring 63 MW of the 212 MW of Scherer capacity into rates.[41] The bulk of this capacity (44 MW) had become available as a result of a default by Gulf States Utilities on a wholesale power contract with Gulf. Mr. Deason acknowledges that the commission denied this request to put a

[41] Docket No. 891345-EI, and Deason Direct Testimony, at 17.

portion of Scherer into rate base because: 1) there was no current need for the capacity on the retail system; 2) the proposal for the 44 MW was only being made because of the contract default; and 3) that because only the shareholders derived benefit from the off-system sales they should absorb any liability related to an inability to sell wholesale power and retail customers should be insulated from this liability. [42]

Q. What do you conclude from the Commission's decision in that proceeding?

A. The issue there was directly analogous to Gulf's proposal today in two ways. First, the Commission found that a current lack of need for the available capacity was important and a reason for not burdening customers with the unnecessary costs. I have already described how this is also true for Scherer 3, and Gulf confirms this with its own data.[43] Second, because the off-system sales had the potential to benefit shareholders rather than customers, the Commission found that shareholders now faced with a potential financial loss from the default should absorb this liability. This is also clearly analogous to the present Scherer situation, where Gulf has attempted but failed to find buyers for its excess capacity at its required return and is therefore now proposing to shift this financial burden to its customers. In neither case was there a customer need for the added capacity. customers despite them not needing it.

[42] *Ibid.*

[43] Exhibit PHM-3.

Q. What evidence do you have that Gulf's decision to allocate Scherer power to customers was driven by the fact that it was no longer able to profitably engage in off-system sales.

A. In its response to discovery, Gulf explains its efforts in recent years to enter into either long term wholesale contracts, or to pursue an asset sale.[44] Gulf pursued numerous long-term wholesale contracts, both solicited and unsolicited, including 13 RFPs, without success. They also explored possible asset sales and determined that "there do not currently appear to be any **economically viable** asset sale opportunities." [emphasis added][45] This response indicates that Gulf made serious efforts to either sell the Scherer asset or capacity but could not find buyers in the market and therefore is now attempting to off-load it to its captive customers.

Q. Please summarize your testimony regarding Gulf's proposal to move Scherer 3 into rate base.

A. My testimony shows that Gulf's proposal to burden ratepayers with financial responsibility for Scherer 3 capacity is not justified or in the public interest, because:

1. Customers have no need for new capacity resources through at least 2023, so absorbing Scherer 3 power now will not benefit them.

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[44] Exhibit PHM-2.
[45] *Ibid.*

2. Any need for new capacity or energy resources in 2023 and beyond is speculative, and there is ample time to refine forecasts and procure alternative resources later if necessary.

3. It will exacerbate an already dangerously undiversified portfolio at a time when heavy exposure to coal resources is considered financially risky by many in the industry, it diverges from current trends to divest of coal resources, and alternative renewable resources are both affordable and could provide a hedge against such risk.

4. Gulf has failed to analyze any alternatives to meet the need in 2023 and beyond, consistent with planning best practices and the desire to identify the least cost solutions.

5. Not only has Gulf failed to analyze whether Scherer 3 is an optimal and least cost solution for its ratepayers, but there is substantial evidence that it is not, and that Gulf has plenty of time to perform this analysis and procure alternative resources.

Q: Does this conclude your testimony?

A. Yes.

Exhibit PHM-1

PHILIP H. MOSENTHAL, PARTNER

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PROFESSIONAL EXPERIENCE

Optimal Energy, Hinesburg, *VT. Founding Partner*, 1996-present.

As the Founding Partner Mr. Mosenthal is responsible for business development as well as direct consulting and analysis for numerous electric and gas utilities, government entities and other non-utility parties on energy efficiency, resource planning, regulatory issues, program design, and evaluation and market assessments. Mr. Mosenthal has over 30 years' experience in energy efficiency consulting, including facility energy management, utility and state planning, regulatory policy, program design, implementation, evaluation, and research. He has particular expertise in efficiency regulatory policy, cost-benefit analysis, and commercial, industrial and institutional sector planning and program design and evaluation. Mr. Mosenthal has developed numerous utility, state, and regional integrated resource and DSM plans, and has designed and evaluated energy efficiency programs throughout North America, Europe, and China. He has also led numerous efficiency and renewables potential studies and is a nationally recognized expert on efficiency resource assessment. Mr. Mosenthal has played key roles in many utility-stakeholder processes and successfully worked to build consensus among diverse parties in various assignments. This work has included leading policy and planning initiatives related to goal setting, EM&V frameworks, cost recovery, and performance incentives. Mr. Mosenthal has testified before numerous regulatory commissions, state legislatures, and the U.S. Nuclear Regulatory Commission. Mr. Mosenthal also has designed program implementation procedures, managed implementation contracts, trained efficiency program and planning staff, and performed numerous commercial and industrial facility energy efficiency analyses for end users.

Resource Insight, Middlebury, VT. *Senior Research Associate*, 1995-1996.

At Resource Insight Mr. Mosenthal consulted on DSM planning, program design, monitoring and evaluation, and resource characterization, specializing in the commercial and industrial sectors. He performed projects on behalf of utility and non-utility parties, in both cooperative settings and in contested regulatory proceedings.

Xenergy, Incorporated (now DNV-GL), Allendale, NJ. *Chief Consultant*, 1990-1995.

Mr. Mosenthal managed the consulting division for Xenergy's (now DNV-GL's) Research, Planning and Evaluation Group (RP&E) in its Mid-Atlantic Region. His responsibilities included direct utility consulting, as well as marketing, administration and staff management for RP&E. Mr. Mosenthal's consulting activities focused on assessment of DSM technology potential, DSM planning, program design and development, and process and impact evaluation for electric and gas utilities.

Private Consultant, Philadelphia, PA. 1988-1990.

Mr. Mosenthal's clients included non-profit, governmental and private entities. He performed energy-related research, developed and analyzed potential energy efficiency programs, wrote reports and proposals, aided in contract negotiations and performed building energy audits.

Community Energy Development Corp. (CEDC), Philadelphia, PA. *Acting Executive Director,* 1986-1988.

With simultaneous positions as General Manager of Citizens Coalition for Energy Efficiency (C2E2) and General Manager of Community Energy Consumers (CEC), Mr. Mosenthal managed all aspects of CEDC, C2E2 and CEC operations including: program design and development; program implementation; provision of energy efficiency consulting services for multifamily and institutional building owners; and delivery of a fuel oil cooperative program. CEDC and C2E2 were non-profit organizations providing direct energy efficiency services and energy policy research, respectively. CEC was a for-profit CEDC subsidiary that brokered fuel oil for commercial and residential customers.

Pennsylvania Energy Center, Philadelphia, PA. *Director of Technical Services,* 1983-1986

As director of technical services, Mr. Mosenthal managed, designed and developed energy services for the southeast regional branch of the Pennsylvania State Energy Office. He designed and developed technical energy services for commercial, industrial and institutional building owners; supervised staff of energy auditors and subcontractors; performed over 400 commercial and industrial energy audits; and taught energy management workshops.

EDUCATION AND LICENSING

University of Pennsylvania, Philadelphia, PA
Master of Science, Energy Management and Policy, 1990

University of Pennsylvania, Philadelphia, PA
Bachelor of Arts, Design of the Environment, 1982

Pennsylvania State University, Ambler, PA
Certificate in Electrical Engineering, 1984

REPRESENTATIVE PROJECT EXPERIENCE

Efficiency Program Design and Planning

Massachusetts Energy Efficiency Advisory Council, Technical Consulting Services (2006 – present)
Optimal Energy has led the Technical Consultant team for the Massachusetts Energy Efficiency Advisory Council (EEAC) since its inception in 2006. Mr. Mosenthal has served in various roles on this team, including overall Team Manager, Team lead for the commercial and industrial sector, and senior advisory on planning, programs, and EM&V. Optimal's role includes representing the EEAC on all aspects of negotiating efficiency programs, plans, goals and budgets with the program administrators, and oversight of all program implementation and evaluation, monitoring and verification activities. Prior to the EEAC's inception, Mr. Mosenthal served as a manager and lead for the C&I sector on numerous Massachusetts' Utility Collaboratives working directly with the utilities on behalf of the non-utility parties, from 1998-2006.

Rhode Island Energy Resource Management Council, Technical Consulting for the Energy Resource Management Council (2006 – present)
Optimal Energy has led the Technical Consultant team for the Rhode Island Energy Resource Management Council (ERMC) since its inception in 2006. Mr. Mosenthal has served in various roles on this team, including as the team lead for the commercial and industrial sector, and senior advisor on planning, programs, and EM&V. Optimal's role includes representing the ERMC on all aspects of negotiating efficiency programs, plans, goals and budgets with National Grid, the program administrator. We also provide oversight of all program implementation and evaluation, monitoring and

verification activities.

Efficiency Vermont, Consulting Services (2000 – present)
Since Efficiency Vermont's (EVT) inception in 2000, Optimal has served as a consultant to the world's first Energy Efficiency Utility. In this role, Optimal has performed numerous planning and program design and assessment studies for EVT. Mr. Mosenthal's roles have included leading the commercial and industrial planning team, representing EVT before the VT Department of Public Service in assessing, evaluating and verifying commercial and industrial sector savings, development of the nation's first Technical Resource Manual, negotiating performance incentives with the VT Public Service Board, and leading various market analyses.

New York State Energy Research and Development Authority, Statewide Efficiency and Renewable Potential Studies (2003 – present)
Optimal has led numerous studies for NYSERDA to assess the energy efficiency and renewable potential throughout New York. Mr. Mosenthal has managed a number of these studies, as well as served as the lead investigator for the commercial and industrial segments. Studies have assessed the efficiency potential from electricity, natural gas, and petroleum fuels, as well as the electric and thermal potential from renewable energy resources. Numerous studies have considered the potential statewide, as well as by utility region and load control zone.

New York State Energy Research and Development Authority, Statewide Efficiency and Renewable Combined Heat and Power Market Assessment (2014)
Optimal led an analysis and market assessment of the potential achievable economic and environmental impacts from adoption of combined heat and power (CHP) technologies throughout New York, and by utility and load control region. Mr. Mosenthal served as a senior advisor on this project.

New York State Energy Research and Development Authority, Statewide Efficiency and Renewable Heat Pump Assessment (2014)
Optimal led an analysis and market assessment of the potential achievable economic and environmental impacts from adoption of air source and ground source heat pumps in the residential and commercial sectors. This analysis included assessing the energy savings potential and cost-effectiveness of heat pump technology as compared to fossil-fuel-fired thermal solutions, and considered the overall likely economic and environmental impacts of conversion of building thermal loads to heat pumps.

New York Power Authority, Various Analyses and Studies (1990 – present)
Beginning in 1990 Mr. Mosenthal has led numerous projects for the New York Power Authority. These have included numerous efficiency potential assessments, both territory wide, and for selected market segments and or municipal or governmental customers. These studies identified and assessed possible efficiency opportunities, and modeled likely penetrations and economic and environmental impacts from various program and planning scenarios. Optimal has also developed targeted analyses of the efficiency potential in State Agency facilities, leading to two Executive Orders passed by Governor's Spitzer and Cuomo. Optimal also developed NYPA's evaluation, monitoring and verification plans, has assisted NYPA in developing and implementing EM&V and cost-effectiveness frameworks, advised on program implementation, and developed innovative strategies and proposals to address geographic transmission and distribution constraints.

Illinois Office of the Attorney General, Advisor on Energy Efficiency Planning, Design, Implementation and Evaluation (2007 – present)

Mr. Mosenthal has served as the project manager and lead advisor to the Illinois Office of the Attorney General on all aspects relating to energy efficiency program planning, design, implementation, evaluation and general oversight of utility electric and gas efficiency programs throughout Illinois. In this role, Mr. Mosenthal represents the IL AG in a collaborative stakeholder process with the utilities and other parties. Mr. Mosenthal has also assisted with legislative and regulatory issues, provided expert testimony in numerous dockets before the Illinois Commerce Commission, assisted in development of grid modernization rules and policies, and worked on electric procurement issues related to the Illinois Power Agencies resource procurement process and mechanisms.

Natural Resources Defense Council, Sierra Club and Renew Missouri, Consultant and Expert Witness on Electric and Gas Energy Efficiency Programs and Planning (2009 – present)
Mr. Mosenthal has served as the project manager and lead advisor to Natural Resources Defense Council, Sierra Club and Renew Missouri on efficiency program planning and design, cost-effective potential, critical review of utility integrated resource plans, participation in utility-specific and statewide collaboratives. This project has involved expert testimony in numerous dockets before the Missouri Public Service Commission related to Ameren and Kansas City Power & Light efficiency efforts, work on development of commission rules related to integrated resource planning and the Missouri Energy Efficiency Investment Act, and direct negotiation with parties on goals, budgets and efficiency programs and policies.

U.S. Environmental Protection Agency, Advising to the Ohio Office of Energy Efficiency on State Efficiency Planning, Programs and Policy (2006 – 2009)
Mr. Mosenthal has served as the project manager and ;ead advisor to the Ohio Office of Energy Efficiency on policy, planning and program design on behalf of U.S. EPA's Clean Energy Partnerships with State and Local Governments to advance State Clean Energy Action Plans. Project included reviewing past performance and current policy, plans and funding, and advising on new programs and funding commitments.

Massachusetts Non-Utility Parties, Technical Consultants to the Non-Utility Parties in Multiple Utility Collaboratives (1998 – 2006)
Mr. Mosenthal service as a C&I consultant and Sector Team Lead representing the non-utility parties (NUPs) in multiple utility collaboratives, including for Boston Edison, Commonwealth Electric, Cambridge Electric, Eastern Utilities, Massachusetts Electric, NSTAR and Western Massachusetts Electric In this role Mr. Mosenthal advised on policy, planning, program design, negotiations of goals and budgets, and evaluation, monitoring and verification.

Natural Resources Defense Council, Development of a Clean Energy Power Plant in China (July 2003 – 2007)
Mr. Mosenthal served as the Consulting team C&I Sector leader on development and assessment of demand-side management investment portfolios for China, for the Natural Resources Defense Council. This project included developing and analyzing the potential for a portfolio of efficiency programs to serve as model programs for China in the Provinces of Shanghai and Jiangsu and the municipality of Chong Ching. It included addressing political and regulatory barriers, long term funding mechanisms and development of an administrative organizational structure, as well as analyzing the efficiency opportunities and designing efficiency programs. Mr. Mosenthal also served as a trainer and instructor to the China State Electrical Grid, local utilities and other stakeholders. This project led to development of a $500 million fund from the Asian Development Bank to invest in efficiency programs.

Cape Light Compact, Program Planning and Design (2003 – 2005)

Mr. Mosenthal served as project manager assisting the Cape Light Compact in designing a portfolio of C&I programs, development of savings goals and budgets, and analysis of measures, cost-effectiveness and implementation issues. Projects have included revising the current offerings to improve and expand them, and to bring greater consistency with other Massachusetts utility programs. This project also included assistance with evaluation, monitoring and verification through improved savings estimates.

Connecticut Municipal Electric Consortium, Program Planning and Design (2005 – present)
Optimal assisted the Connecticut Municipal Electric Consortium to design and develop a portfolio of municipal efficiency programs. This project included analysis of opportunities and design and development of program designs, and implementation services including development of tracking systems and provision of technical services directly to C&I customers. Mr. Mosenthal served as a senior advisor on commercial and industrial program planning and development.

Vermont Electric Power Company, Northwest Reliability Project and Southern Loop Alternatives Project (2005 – 2008)
Optimal assisted the Vermont Electric Power Company in two separate projects to analyze and propose resource solutions to address transmission and distribution (T&D) constrained areas in Northwest and Southern Vermont. In both these projects Mr. Mosenthal lead the analysis for the commercial and industrial sectors. This included analyzing the energy efficiency potential in the regions, proposing and designing portfolios of efficiency programs to avoid or defer the need for substantial T&D upgrades, assessment of the economic and environmental impacts of pursuit of the efficiency alternatives, and providing expert testimony in support of alternative targeted efficiency strategies.

Connecticut Office of Consumer Counsel, Design of Efficiency Policy and Shareholder Performance Incentives (2003 – 2004)
Optimal provided consulting and expert testimony on behalf of the Connecticut Office of Consumer Counsel related to setting energy efficiency policy, goals and development of utility shareholder performance incentives. Mr. Mosenthal served as the C&I sector analysis lead, and as an expert witness.

Long Island Power Authority, Program Design, Development, Planning and Implementation Support (1998 – 2007)
Optimal Energy led the development and analysis of a portfolio of C&I market transformation and retrofit programs for the Long Island Power Authority. This project includes program design of utility and regional market transformation programs targeting new and replacement building and equipment markets, and the estimation of the achievable potential for selected markets on Long Island. In addition, Optimal served as LIPA's lead consultants on all aspects of planning, program design, reporting and EM&V, on an on-going basis. Mr. Mosenthal served as team lead for the C&I sector.

Northeast Energy Efficiency Partnerships, Economic and Technical Advisor on Program Design, Planning and Resource Assessment (1998 – 2008)
Optimal has served as an economic and technical advisor to Northeast Energy Efficiency Partnerships, a not-for-profit regional consortium of utilities pursuing market transformation in efficiency markets. Various studies have included: economic analysis and report on cost-effectiveness of NEEP initiatives involving high-efficiency motors, CoolChoice unitary HVAC, clothes washers, and residential lighting; and multiple assessments of the energy efficiency potential in the Northeast U.S.

New York City, NRDC, PACE, et. al., Natural Gas Energy Efficiency Potential and Program Design (2004)
Led a commercial and industrial sector analysis and report on gas energy efficiency programs for Consolidated Edison of New York, on behalf of New York City Economic Development Corporation,

NRDC, Pace Energy Project, Association for Energy Affordability and Public Utility Law Project.

New Jersey Clean Energy Collaborative, Advisor on Commercial and Industrial Program Planning, Design and Implementation (November 1996 – 2003)
Mr. Mosenthal served as a commercial sector advisor on program planning and implementation of multi-year statewide energy-efficiency programs in the New Jersey Clean Energy Collaborative involving all the state's electric and gas utilities and the Natural Resources Defense Council. Initially he co-directed collaborative work on program development, planning, and implementation for Conectiv prior to representing NRDC in the Collaborative process.

Citizens Utilities Corporation's Arizona Electric Division, Design and Development of Efficiency Programs (2000 – 2001)
Optimal served as advisors to the Citizens Utilities Corporation's Arizona Electric Division, developing a program strategy to capture maximum achievable potential among targeted sectors to effect immediate load reductions in response to energy shortages and rate shock resulting from the California electric market. This project included assessing the efficiency and load reducing opportunities, and developing implementation strategies to capture them, among food processing and storage, wastewater treatment and school facilities.

Vermont Department of Public Service, Design and Development of a Statewide Efficiency Utility and Portfolio of Electric Efficiency Programs (1995 – 2000)
Mr. Mosenthal served as a lead consultant on all aspects of the development and structure of a new Statewide Efficiency Utility. Mr. Mosenthal also led the design and analysis of a portfolio of DSM programs to be initially delivered by the efficiency utility, as well as institutional, regulatory, organizational and evaluation processes to support the ongoing transformation from electric utility led programs to an independent entity. The project involved program design and development; measure characterizations; analysis of program impacts and costs; assessment of achievable market-driven and retrofit potential; modeling of program participation; economic screening; and development of monitoring and evaluation guidelines. The project also developed criteria for the delivery of the core programs during a transition to the efficiency utility and electric utility restructuring, and established the proposed structure and role of the efficiency utility.

Resource Planning and Policy

Efficiency Vermont, Energy Efficiency Potential Analyses (2008 – 2013)
Mr. Mosenthal served as the lead analyst on development of electric and unregulated fuels C&I efficiency potential and development of 20-year forecasts of expected Efficiency Vermont achievements under various policy, planning and funding scenarios. This project included zonal analysis to support distributed utility planning for transmission system reliability and for all 22 VT electric utilities distribution system planning. Mr. Mosenthal has also served as a senior advisor on additional follow-up studies.

U. S. Environmental Protection Agency, EPA Clean Energy Partnership, State Clean Energy Action Plans (2006 — 2009)
Lead energy efficiency analysis, research and product development for EPA's Clean Energy Partnership with State and Local Governments to advance State Clean Energy Action Plans. Projects included development of a Clean Energy Fund Manual to guide state planners in development of Clean Energy Action Plans; development of an energy efficiency potential assessment guide as part of the EPA's National Action Plan on the use, value and performance of efficiency and renewable potential assessments; and development of multi-year plans for efficiency programs for Ohio Office of Energy

Efficiency. For EPA.

Northeast Energy Efficiency Partnerships, New England Efficiency Potential (2009 – 2010 & 2014)
Optimal performed two separate region-wide studies to estimate the efficiency potential in New England on behalf of the Northeast Energy Efficiency Partnerships. Mr. Mosenthal served as the lead analyst on the first study and as senior advisor on the second.

Delaware Department of Natural Resources and Environmental Control, Delaware Efficiency Potential Study (2012 – Present)
Lead analyst and senior advisor on a project to estimated detailed electric and gas efficiency potential in the State of Delaware. This study was intended to support current legislative efforts in Delaware to establish efficiency targets and funding mechanisms. As a follow up to this study, Optimal continues to advise DNREC and the Delaware Energy Efficiency Advisory Council on development of efficiency and EM&V policies and frameworks, and oversee the utility planning process. Mr. Mosenthal was a lead author and developer of EM&V regulations in Delaware.

MO Department of Natural Resources, Critical Review of Utility Integrated Resource Plans (2006 – 2010)
Optimal served as advisors to the Missouri Department of Natural Resources in leading critical review and developing formal comments on utility IRPs, efficiency potential studies, and planning issues. Mr. Mosenthal served as project manager and lead investigator.

Natural Resources Defense Council, Ceres, Environmental Defense Fund and Public Citizen, Texas Assessment of Electric Efficiency Potential and Policy Recommendations (2006 – 2009)
Principal investigator and author of an assessment of electric efficiency potential and policy recommendations for Texas as an alternative to supply-side investment in coal-fired power plants. Analyzed the residential, commercial and industrial potential for electric load reductions from efficiency programs, appliance standards, enhanced building codes, demand response and combined heat and power programs. Also recommended policy and programmatic changes to advance efficiency in Texas. Provided expert testimony before the Texas Legislature.

New York State Energy Research and Development Authority, Statewide Efficiency and Renewable Potential Studies (2003 – present)
Optimal has led numerous studies for NYSERDA to assess the energy efficiency and renewable potential throughout New York. Mr. Mosenthal has managed a number of these studies, as well as served as the lead investigator for the commercial and industrial segments. Studies have assessed the efficiency potential from electricity, natural gas, and petroleum fuels, as well as the electric and thermal potential from renewable energy resources. Numerous studies have considered the potential statewide, as well as by utility region and load control zone.

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environmental impacts from adoption of air source and ground source heat pumps in the residential and commercial sectors. This analysis included assessing the energy savings potential and cost-effectiveness of heat pump technology as compared to fossil-fuel-fired thermal solutions, and considered the overall likely economic and environmental impacts of conversion of building thermal loads to heat pumps.

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Beginning in 1990 Mr. Mosenthal has led numerous projects for the New York Power Authority. These have included numerous efficiency potential assessments, both territory wide, and for selected market segments and or municipal or governmental customers. These studies identified and assessed possible efficiency opportunities, and modeled likely penetrations and economic and environmental impacts from various program and planning scenarios. Optimal has also developed targeted analyses of the efficiency potential in State Agency facilities, leading to two Executive Orders passed by Governor's Spitzer and Cuomo. Optimal also developed NYPA's evaluation, monitoring and verification plans, has assisted NYPA in developing and implementing EM&V and cost-effectiveness frameworks, advised on program implementation, and developed innovative strategies and proposals to address geographic transmission and distribution constraints.

Illinois Office of the Attorney General, Advisor on Energy Efficiency Planning, Design, Implementation and Evaluation (2007 – present)
Mr. Mosenthal has served as the project manager and lead advisor to the Illinois Office of the Attorney General on all aspects relating to energy efficiency program planning, design, implementation, evaluation and general oversight of utility electric and gas efficiency programs throughout Illinois. In this role, Mr. Mosenthal represents the IL AG in a collaborative stakeholder process with the utilities and other parties. Mr. Mosenthal has also assisted with legislative and regulatory issues, provided expert testimony in numerous dockets before the Illinois Commerce Commission, assisted in development of grid modernization rules and policies, and worked on electric procurement issues related to the Illinois Power Agencies resource procurement process and mechanisms.

Natural Resources Defense Council, Sierra Club and Renew Missouri, Consultant and Expert Witness on Electric and Gas Energy Efficiency Programs and Planning (2009 – present)
Mr. Mosenthal has served as the project manager and lead advisor to Natural Resources Defense Council, Sierra Club and Renew Missouri on efficiency program planning and design, cost-effective potential, critical review of utility integrated resource plans, participation in utility-specific and statewide collaboratives. This project has involved expert testimony in numerous dockets before the Missouri Public Service Commission related to Ameren and Kansas City Power & Light efficiency efforts, work on development of commission rules related to integrated resource planning and the Missouri Energy Efficiency Investment Act, and direct negotiation with parties on goals, budgets and efficiency programs and policies.

Wal-Mart, Wal-Mart Energy Efficiency Rate Tariff Design and Analysis (2005 — 2006)
Developed an innovative "efficiency rate tariff" designed to benchmark commercial facilities energy efficiency and price electricity to them based on their efficiency levels to create incentives for efficiency and reduce cross subsidies. This electric rate would develop threshold efficiency levels by facility type with increasing block rates that remove current disincentives to efficiency that exist with traditional electric rate design. Mr. Mosenthal served as project manager and lead investigator.

Citizens for Pennsylvania's Future, Development of Framework for Efficiency as a Resource Under an Alternative Energy Portfolio Standard (February 2005 – 2006)
Consulting team C&I leader providing technical assistance supporting rulemaking to implement energy-efficiency provisions as qualifying resources for the Pennsylvania Alternative Energy Portfolio Standard. Developed policies, mechanisms and sample verification protocols for inclusion of efficiency resources to meet AEPS standards.

Vermont Electric Power Company, Northwest Reliability Project and Southern Loop Alternatives Project (2005 – 2008)
Optimal assisted the Vermont Electric Power Company in two separate projects to analyze and propose resource solutions to address transmission and distribution (T&D) constrained areas in Northwest and Southern Vermont. In both these projects Mr. Mosenthal lead the analysis for the commercial and industrial sectors. This included analyzing the energy efficiency potential in the regions, proposing and designing portfolios of efficiency programs to avoid or defer the need for substantial T&D upgrades, assessment of the economic and environmental impacts of pursuit of the efficiency alternatives, and providing expert testimony in support of alternative targeted efficiency strategies.

Connecticut Office of Consumer Counsel, Design of Efficiency Policy and Shareholder Performance Incentives (2003 – 2004)
Optimal provided consulting and expert testimony on behalf of the Connecticut Office of Consumer Counsel related to setting energy efficiency policy, goals and development of utility shareholder performance incentives. Mr. Mosenthal served as the C&I sector analysis lead, and as an expert witness.

Vermont Department of Public Service, State of VT Economically Achievable Efficiency Potential (2001 – 2003)
C&I project lead for consulting team performing a statewide projection of economically achievable efficiency potential for state of Vermont.

Vermont Department of Public Service, Distributed Utility Alternatives Screening Tool (September 2001 – December 2002)
C&I project lead for consulting team supporting utilities in targeting demand-side resources to optimize distribution investment planning by easily assessing alternative resource options for as part of a statewide distributed utility planning collaborative. This project included developing a unique "distributed utility screening tool" that allowed small municipal and cooperative utilities to easily estimate achievable potential in their jurisdiction as a first step in considering least cost alternatives to infrastructure investment for distributed utility planning.

Maine Office of the Consumer Advocate, State of Maine Electric Efficiency Achievable Potential (2002)
Analyzed the C&I electric efficiency achievable potential for the State of Maine. This project included estimated economic and achievable opportunities over 10 years, in support of development of a statewide efficiency administration model.

American Council for an Energy Efficient Economy, State of Michigan Electric Efficiency Achievable Potential (2002 - 2003)
Analyzed the C&I electric efficiency achievable potential for the State of Michigan. This project included estimated economic and achievable opportunities over 10 years, in support of potential development of a statewide efficiency policies and goals.

Evaluation, Monitoring and Assessment

Enbridge Gas Distribution, Evaluation Audit (2013-2015)
Optimal served as the EM&V auditor for all Enbridge Gas Systems evaluations for program years 2013 and 2014, on behalf of Enbridge and the Ontario Energy Board. This involved reviewing the processes and analyses used for the impact evaluation and making recommendations on ways to improve the programs, as well as developing realization rates for each program. Mr. Mosenthal served as lead auditor for the commercial and industrial retro commissioning programs.

Massachusetts Energy Efficiency Advisory Council, Technical Reference Manual for the State of Massachusetts (2008 – 2012)
Team leader on development of a statewide Technical Reference Manual for the State of Massachusetts in collaboration with the MA electric and gas utilities. This project included working with the program administrators to establish and document the initial policies and rules around development, maintenance, and usage of a statewide TRM, as well as development of the first TRM version to guide Massachusetts EM&V.

Natural Resources Defense Council, Kyoto Protocol, Clean Development Mechanism Framework and M&V Protocols (2004 — 2007)
Development of M&V protocols and mechanisms for two Chinese provinces to sell energy efficiency portfolio carbon dioxide savings into the Clean Development Mechanism (CDM) established under the Kyoto Protocol.

New York State Energy Research and Development Authority, Small C&I Lighting Market Assessment (2003 - 2005)
Market assessment of small commercial lighting market and activity support to the evaluation and design of a NYSERDA Small C&I Lighting Program. This project included advising on scope of analysis and interpretation of interview and survey data, and review and recommendations on program design and implementation.

Multiple Clients, Development of EM&V Plans and Technical Reference Manuals (2000 – Present)
Mr. Mosenthal was a key stakeholder in leading the development of the first technical reference manual in North America, and was the lead analyst and negotiator for the development of the commercial and industrial sector TRM entries, for Efficiency Vermont in the early 2000's. Since then, Mr. Mosenthal has served as a senior advisor on the development of numerous EM&V frameworks, plans and technical reference manuals in a number of jurisdictions, including projects in: DE, IA, IL, IN, OH, LA, MO, NC, NJ, NY, PA, MD, MA, RI and VT.

Massachusetts Energy Efficiency Advisory Council, and Rhode Island Energy Resource Management Council, Code Compliance Initiative EM&V Plans and Framework (2013 – Present)
On behalf of the MA EEAC and separately for the RI EERMC, Mr. Mosenthal has directly negotiated and developed an EM&V framework for attributing savings from a code compliance and standards initiative. In this capacity Mr. Mosenthal has also reviewed and contributed to all EM&V planning for the codes and standards efforts.

Efficiency Vermont, C&I Evaluation Planning, Savings Verification and Coordination (2000 – 2008)
Mr. Mosenthal served as the lead advisor and negotiator to Efficiency Vermont on C&I evaluation planning and coordination with Department of Public Service on evaluation and savings estimation and verification.

Long Island Power Authority Advisor, C&I Baseline and Market Assessment (1999 - 2001)
Lead advisor to Long Island Power Authority on its C&I baseline analysis and market assessment. Project included support in developing program and market theory, evaluation plans and RFP, review of proposals, and ongoing advice and critical review of a third party analysis.

Orange and Rockland Utilities, Impact Evaluations (1994 – 1995)
Mr. Mosenthal managed a project and served as the lead investigator for performing impact evaluations on all programs within Orange & Rocklands energy efficiency portfolio.

Exhibit PHM-2

130. Scherer Unit 3. The Southern Company and Subsidiary Companies Form 10-Q for the Quarter Ended June 30, 2016 (provided in MFR Section F, Volume 2), at page 82 in discussing Gulf's ownership interest in Scherer Unit 3, states: "Gulf Power is actively evaluating alternatives, including, without limitation, rededication of the assets to serve retain customers for whom it was originally planned and built, replacement long-term wholesale contracts or other sales into the wholesale market, or asset sale."

a. Please provide a detailed description of the steps taken by Gulf in evaluating each of these various options discussed in the Form 10-Q.

b. Provide a detailed description of the current status of each of the separate options discussed in the Form 10-Q as being considered.

ANSWER:

Scherer Unit 3 was planned, acquired and ultimately built for the purpose of serving Gulf's native load customers. Scherer 3 was found by the Commission to be a cost-effective alternative to construction of a generating unit that had been planned at Gulf's Caryville site to serve those same retail customers. The Commission encouraged Gulf to proceed with the purchase of an interest in Scherer 3 and to enter into long-term wholesale contracts to cover the unit's cost on an interim basis. All parties expected that Scherer 3 would ultimately return to retail service.

As the latest series of wholesale contracts expire, Gulf's Scherer 3 investment is being rededicated to serving those customers for whom it was originally planned, acquired and built. The portion of Scherer 3 no longer subject to wholesale contracts is now used and useful in providing service to Gulf's retail customers.

At the same time, as referenced in the Form 10-Q, Gulf has evaluated, and continues to evaluate, other options for this retail asset that might serve the interests of its retail customers. The following is a description of the steps taken by Gulf to evaluate those options and the current status of such options.

<u>Replacement Long-Term Wholesale Contracts</u>

a. Southern Wholesale Energy (SWE) on behalf of Gulf Power has continuously taken steps to evaluate the option of entering into replacement long-term wholesale contracts for Gulf's portion of Scherer Unit 3. Since 2011, SWE has evaluated the market for any potential long-term wholesale contract opportunities for Scherer 3 to fulfill upcoming base load capacity needs for other entities. These opportunities include both solicited offers in response to an entity's

Requests for Proposals (RFPs) and unsolicited offers to potential counterparties identified by SWE.

Upon identification of any long-term wholesale opportunity by SWE, Gulf management would evaluate each proposal and offer to determine if it would be a suitable option for Gulf's portion of Scherer Unit 3 and would determine the appropriate pricing structure for each proposal that would maintain the financial strength of the Company over the long term. Through these efforts, Gulf and SWE have formally responded to 13 separate RFPs for base load capacity with Scherer Unit 3 as the underlying generating unit. Responses to the RFPs include various capacity amounts and pricing structures as needed by the requesting entity. All submitted RFP responses to this point have been fully evaluated by the entities initiating the RFP.

In addition to the formal RFP responses discussed above, SWE also identified and contacted other potential counterparties for long-term wholesale contracts, and discussions were held with these entities to establish interest in Scherer Unit 3 as a possibility for upcoming capacity and energy needs. All previously established discussions with these potential counterparties have been completed.

b. The RFP responses and unsolicited offers have not resulted in any additional long-term wholesale contracts.

Short-Term Sales into the Wholesale Market

a. Beginning in October 2015, Gulf and Southern Company Services Term Trading (Term Trading) began evaluating additional wholesale opportunities for Gulf's portion of Scherer Unit 3 in external forward markets.

On an ongoing basis, Term Trading performs analyses of unit cost versus value available in external forward markets for both on-peak and off-peak periods. Term Trading constantly monitors market conditions and valuations and provides Gulf with monthly updates of market expectations for the upcoming months. In addition to the monthly updates, Term Trading notifies Gulf when value from forward external market opportunities are expected to exceed the value of retaining Scherer and provides recommendations to Gulf on the months, days, hours and pricing that would meet the valuation threshold. Gulf subsequently reviews all Term Trading recommendations and provides approval to transact on these forward market opportunities to the extent Term Trading is able to successfully identify counterparties in need of energy during this period.

b. The status of all forward market transactions initiated by Term Trading is provided below.

Transaction Dates	MW	Period	Status
July & August 2016	50	On-Peak	Completed
7/18/16-7/31/16	50	On-Peak	Completed
January & February 2017	50	On-Peak	Finalized
January & February 2017	50	On-Peak	Finalized
January & February 2017	100	Off-Peak	Finalized

Asset Sale

a. SWE has also been involved in evaluating asset sale opportunities related to Gulf's portion of Scherer Unit 3. All previously established discussions with potential counterparties have been completed. Separately, in 2015, an informal and high-level analysis of a potential asset sale was performed for Gulf by a third-party investment banking firm for discussion purposes only. No specific opportunities were pursued as a result of this analysis.

b. There do not currently appear to be any economically viable asset sale opportunities.

Exhibit PHM-3

Scherer Unit 3

64. Please provide a projection of Gulf's Seasonal Reserve Margin with and without Scherer Unit 3, for the period 2015 through 2025. As part of your response, please state when Scherer Unit 3 is first required for reserve margin purposes. Please provide the requested calculation data electronically in MS Excel format with all formulas intact.

ANSWER:

As shown in the table below, Scherer Unit 3 is required to meet a portion of Gulf's projected 2023 and beyond reserve margin requirement. Other resources will also be required in addition to Scherer Unit 3 due to the magnitude of the reserve margin requirement that starts in 2023.

The requested projection is provided in the spreadsheet titled "Gulf 2016-2025 RM - with and without Scherer 3.xlsx" included in the folder named Staff_ROG_064 on the DVD labeled Docket No. 160186-EI Staff's Third Set of Interrogatories (No. 39-98) Disc 1.

			Gulf Net Capability (MW)					Gulf Reserve Margin	
Year	Scherer 3 MW	Year	Without Scherer 3	With Scherer 3	Year	Gulf Peak Demand	Year	Without Scherer 3	With Scherer 3
2012	0	2012	2,968	2,968	2012	2,351	2012	26.2%	26.2%
2013	0	2013	2,987	2,987	2013	2,362	2013	26.5%	26.5%
2014	0	2014	3,370	3,370	2014	2,437	2014	38.3%	38.3%
2015	0	2015	3,017	3,017	2015	2,495	2015	20.9%	20.9%
2016	161	2016	2,978	3,139	2016	2,450	2016	21.6%	28.1%
2017	161	2017	2,983	3,144	2017	2,491	2017	19.8%	26.2%
2018	161	2018	2,983	3,144	2018	2,520	2018	18.4%	24.8%
2019	161	2019	2,971	3,132	2019	2,546	2019	16.7%	23.0%
2020	211	2020	2,971	3,182	2020	2,552	2020	16.4%	24.7%
2021	211	2021	2,971	3,182	2021	2,554	2021	16.3%	24.6%
2022	211	2022	2,971	3,182	2022	2,554	2022	16.3%	24.6%
2023	211	2023	2,086	2,297	2023	2,564	2023	-18.6%	-10.4%
2024	211	2024	2,086	2,297	2024	2,576	2024	-19.0%	-10.8%
2025	211	2025	2,086	2,297	2025	2,586	2025	-19.3%	-11.2%

* Scherer 3 (211 MW) was committed to wholesale during the 2012-2015 time period.

Exhibit PHM-4

174. Scherer Unit 3. Please refer to the Direct Testimony of Mr. Burleson, pages 19 through 21.

a. Please explain in detail the analysis, if any, Gulf performed to determine use of its post-2015 unsold capacity from its share of Scherer Unit 3 to serve its retail customers is consistent with providing electric service to those customers at lowest reasonable cost.

b. Please explain in detail what, if any, Strategist, System Optimizer, Aurora, PROMOD, Plexos or other resource planning analysis that Gulf has performed, or has had performed on its behalf, to evaluate the risk and present value economics to Gulf's retail customers of utilizing Gulf's share of Scherer Unit 3 starting in 2016 versus other resource options available, or potentially available, to serve Gulf's retail customers starting in 2016 in place of Gulf's share of Scherer Unit 3.

ANSWER:

Gulf has not performed, nor had performed on its behalf, an analysis to evaluate utilizing Gulf's ownership share of Scherer Unit 3 to serve retail customers post-2015 versus other alternatives. Gulf does not believe such an analysis is necessary, for three reasons.

1. Gulf is returning an existing resource, Scherer Unit 3, to serve its retail customers consistent with the original purpose for which it was planned, acquired, and ultimately built, and is not evaluating it as a new resource versus other alternatives.
2. Gulf believes any analysis, if performed, of operating Scherer Unit 3 post-2015 on behalf of its retail customers would show that it is decisively in the retail customers' best interest. Scherer Unit 3 provides capacity value to Gulf Power as well as energy value as a resource dispatched on low variable cost Powder River Basin (PRB) coal. Gulf believes those benefits would easily outweigh the costs to continue to operate Scherer Unit 3, given that it is already a well-controlled unit equipped with a baghouse, a selective catalytic reduction system (SCR), and a flue gas desulfurization system (FGD or scrubber).
3. Gulf believes Scherer Unit 3 provides other, non-quantifiable benefits, such as maintaining a diverse fuel supply, reducing fuel price volatility, providing a hedge against rising gas prices, and it doesn't contribute to greenhouse gas emissions in the state of Florida.

Exhibit PHM-5

IN THE SUPERIOR COURT OF FULTON COUNTY
STATE OF GEORGIA

SIERRA CLUB, INC., ALTAMAHA RIVERKEEPER, INC., COOSA RIVER BASIN INITIATIVE, INC., and SAVANNAH RIVERKEEPER, INC., Plaintiffs, v. RICHARD E. DUNN, *Director of the Environmental Protection Division of the State of Georgia Department of Natural Resources,* Defendant.	)))))))))))))	Civil Action File # 2017CV284719

PETITION FOR WRIT OF MANDAMUS

COME NOW, the Plaintiffs in the above-styled action and file this their Petition for Writ of Mandamus against Defendant Richard E. Dunn, Director of the Environmental Protection Division of the State of Georgia Department of Natural Resources and show the Court as follows:

~Statement of the Case ~

1. National Pollutant Discharge Elimination System ("NPDES") permits regulate the discharge of pollutants from point sources into the waters of the U.S. and into waters of the State of Georgia.

2. This petition seeks issuance of a writ of mandamus directed to Defendant Dunn, to compel him to perform his public duty to grant or deny any permit application within the time specified by O.C.G.A. § 12-2-2(c)(1)(A), and to grant or deny permits for new NPDES permits for five coal-fired power plants in

accordance with O.C.G.A. § 12-5-30(d). By letting these permits—for facilities that discharge large quantities of toxic pollutants into the surface waters of the state of Georgia—languish without update long beyond their prescribed five-year terms, Defendant Dunn has harmed and continues to harm Plaintiffs and their members.

PARTIES, JURISDICTION, AND VENUE

3. Defendant Richard E. Dunn, an individual and public official, is the statutory and duly appointed director of the Environmental Protection Division of the State of Georgia's Department of Natural Resources.

4. Upon information and belief, Defendant Richard E. Dunn resides in Fulton County, Georgia.

5. Defendant Dunn may be served in this action by delivering the Summons and Complaint to him personally at the State of Georgia - Department of Natural Resources \ Environmental Protection Division headquarters at address: ***2 Martin Luther King Drive - Suite 1152, Atlanta, GA 30334***.

6. Plaintiff Sierra Club, Inc. is a California nonprofit corporation, with a Georgia chapter office at address 743 E College Ave - Suite B, Decatur, GA 30030.

7. Plaintiff Altamaha Riverkeeper, Inc. is a Georgia nonprofit corporation with principal office address P.O. Box 4122 - Macon, Georgia 31201.

8. Plaintiff Coosa River Basin Initiative, Inc. is a Georgia nonprofit corporation with principal office at address 408 Broad Street, Rome, GA 30161.

9. Plaintiff Savannah Riverkeeper, Inc. is a Georgia nonprofit corporation having its principal office at address P. O. Box 60 – Augusta, Georgia 30903.

10. Each Plaintiff is interested in having the applicable laws executed, including specifically O.C.G.A. § 12-2-2(c)(1)(A) and O.C.G.A. § 12-5-30(d).

11. Each Plaintiff is interested in having enforced, the public duties imposed on Defendant Dunn by applicable law, including specifically O.C.G.A. § 12-2-2(c)(1)(A) and O.C.G.A. § 12-5-30(d).

12. This Court has subject matter jurisdiction over this case.

13. This Court has personal jurisdiction over Defendant.

14. Venue is proper in this Court.

FACTS

15. Coal-fired power plants are the largest source of toxic water pollution in the United States, dumping more toxics into our waters than the other top nine polluting industries combined. Such toxic pollution includes arsenic, boron, cadmium, chromium, lead, mercury, selenium, and other toxics.

16. Coal-fired power plants are the one of the largest sources of toxic water pollution in the state of Georgia.

17. Toxic water pollution makes its way into water bodies across the state of Georoga, into fish and other aquatic life, and into human bodies, through fish and water consumption, swimming, boating, and other activities.

18. Toxic water pollution—particularly the pollutants arsenic, boron, cadmium, chromium, lead, mercury, selenium—can be hazardous to humans or aquatic life in very small doses (measured in parts per billion) because they do not degrade over time and bio-accumulate, meaning they increase in concentration as they are passed up the food chain.

19. Arsenic causes cancer, including lung cancer, skin tumors, and internal organ tumors, and is also connected to heart problems, nervous system disorders, and intense stomach pain. EPA estimates that nearly 140,000 people per year experience increased cancer risk due to arsenic in fish from coal-fired power plants.

20. Mercury is a highly toxic compound that represents an environmental and human health risk even in small concentrations. Mercury is a bio-accumulating poison that impairs brain development in children and causes nervous system and kidney damage in adults. A fraction of a teaspoon of mercury can contaminate a 25-acre lake. Mercury also accumulates in fish, making them unsafe to eat. The federal Environmental Protection Agency estimates that almost 2,000 children per year are born with lower IQs because of mercury in fish that their mothers have eaten.

21. Selenium, through short-term exposure, can cause hair and fingernail changes, damage to the peripheral nervous system, and fatigue and irritability in humans. Long-term exposure can damage the kidney, liver, and nervous and circulatory systems. Selenium is acutely poisonous to fish and other

aquatic life in even small doses; concentrations below 3-8 micrograms per liter can kill fish, and lower concentrations can leave fish deformed or sterile. Selenium also bio-accumulates and interferes with fish reproduction, meaning that it can permanently destroy wildlife populations in lakes and rivers as it works its way through the ecosystem over a period of years.

22. In addition to toxic metals, coal-fired power plants generate and discharge into surface waters chemical nutrients such as nitrogen and phosphorus that can lead to algal blooms and eutrophication that can choke watersheds and severely damage riverine and estuarine environments.

23. When an existing NPDES permit expires, whether a new NPDES permit is issued is a matter of public interest.

24. When an existing NPDES permit expires, whether a new NPDES permit is issued can affect the rights of third persons.

~ *Plant Bowen* ~

25. In 2007, the then Georgia DNR\EPD Director issued NPDES permit number GA0001449 for discharge of wastewater—from a Bartow County coal-fired power plant known as *Plant Bowen*—into the Euharlee Creek and Etowah River (Coosa River Basin).

26. This Plant Bowen NPDES permit number GA0001449 was effective on November 9, 2007 and expired on June 30, 2012.

27. Plant Bowen has continued to discharge wastewater since after the June 30, 2012 expiration date.

28. Plant Bowen generates and discharges significant quantities of water pollution, including such toxic materials as selenium, mercury, and arsenic. Upon information and belief, Plant Bowen discharged to surface waters over 19,000 pounds of toxic chemicals in 2015.

29. The Plant Bowen NPDES permit number GA0001449 does not set discharge limits or monitoring requirements for selenium, mercury, or arsenic.

~ Plant Hammond ~

30. In 2007, the then Georgia DNR\EPD Director issued NPDES permit number GA0001457 for discharge of wastewater—from a Floyd County coal-fired power plant known as *Plant Hammond*—into Smith Cabin Creek and the Coosa River.

31. This Plant Hammond NPDES permit number GA0001457 was effective on November 9, 2007 and expired on June 30, 2012.

32. Plant Hammond has continued to discharge wastewater since after the June 30, 2012 expiration date.

33. Plant Hammond generates and discharges significant quantities of water pollution, including such toxic materials as selenium, mercury, and arsenic. Upon information and belief, Plant Hammond discharged to surface waters 830 pounds of toxic chemicals in 2015.

34. The Plant Hammond NPDES permit number GA0001457 does not set discharge limits or monitoring requirements for mercury, selenium, or arsenic.

~ Plant McIntosh ~

35. In 2003, the then Georgia DNR\EPD Director issued NPDES permit number GA0003883 for discharge of wastewater—from an Effingham County coal-fired power plant known as *Plant McIntosh*—into the Savannah River.

36. This Plant McIntosh NPDES permit number GA0003883 was effective on August 29, 2003, expired on May 31, 2004, and was a modification of a permit originally issued on June 30, 1999.

37. Plant McIntosh has continued to discharge wastewater since after the May 31, 2004 expiration date.

38. Plant McIntosh generates and discharges significant quantities of water pollution, including such toxic materials as selenium, mercury, and arsenic. Upon information and belief, Plant McIntosh discharged to surface waters over 2,000 pounds of toxic chemicals in 2015.

39. The Plant McIntosh NPDES permit number GA0003883 does not set discharge limits or monitoring requirements for mercury, selenium, or arsenic.

~ Plant Scherer ~

40. In 2002, the then Georgia DNR\EPD Director issued NPDES permit number GA0035564 for discharge of wastewater—from a Monroe County coal-fired power plant known as *Plant Scherer*—into Berry Creek, Lake Juliette (Rum Creek), and the Ocmulgee River.

41. This Plant Scherer NPDES permit number GA0035564 was effective on January 30, 2002 and expired on November 30, 2006.

42. Plant Scherer has continued to discharge wastewater since after the November 30, 2006 expiration date.

43. Plant Scherer generates and discharges significant quantities of water pollution, including such toxic materials as selenium, mercury, and arsenic. The Plant Scherer NPDES permit number GA0035564 does not set discharge limits or monitoring requirements for mercury, selenium, or arsenic. Upon information and belief, Plant Scherer discharged over 22,000 pounds of toxic chemicals in 2015 to surfce waters.

~ Plant Wansley ~

44. In 2006, the then Georgia DNR\EPD Director issued NPDES permit number GA0026778 for discharge of wastewater—from a Heard County coal-fired power plant known as *Plant Wansley*—into Yellowdirt Creek and the Chattahoochee River.

45. This Plant Wansley NPDES permit number GA0026778 was effective on September 1, 2006 and expired on August 31, 2011.

46. Plant Wansley has continued to discharge wastewater since after the August 31, 2011 expiration date.

47. Plant Wansley generates and discharges significant quantities of water pollution, including such toxic materials as selenium, mercury, and arsenic.

Upon information and belief, Plant Wansley discharged to surface waters nearly 8,000 pounds of toxic chemicals in 2015.

48. The Plant Wansley NPDES permit number GA0026778 does not set discharge limits or monitoring requirements for mercury, selenium, or arsenic.

~ Plaintiffs' Injuries ~

49. Plaintiffs have one or more members that use the surface waters affected by one or more of the above-identified NPDES permits.

50. Plaintiffs have one or more members for whom aesthetic and recreational values of the surface waters affected by one or more of the above-identified NPDES permits are lessened by Defendant Dunn's failure and refusal to comply with O.C.G.A. § 12-2-2(c)(1)(A) and O.C.G.A. § 12-5-30(d).

51. The injuries to Plaintiffs' member(s) are fairly traceable to Defendant Dunn's failure and refusal to comply with O.C.G.A. § 12-2-2(c)(1)(A) and O.C.G.A. § 12-5-30(d), and are redressable in this action.

52. Before filing this lawsuit, the Plaintiffs and their allies wrote to Defendant Dunn and requested that he grant or deny the applications for the above-identified power plant NPDES permits, and issue new permits for those power plants, but Defendant Dunn has failed and refused to do so.

53. Before filing this lawsuit, the Sierra Club on behalf of itself and the other Plaintiffs, met with Defendant Dunn's Water Branch Chief James Capp and requested that he grant or deny the applications for the above-identified NPDES

permits, and issue new permits for those power plants, but Defendant Dunn has failed and refused to do so.

54. Before filing this lawsuit, Plaintiffs and their allies sent Defendant Dunn a Notice of their intent to file a lawsuit regarding Plaintiffs' request that Defendant Dunn grant or deny the applications for the above-identified power plant NPDES permits, and issue new permits for those power plants.

55. Plaintiffs were forced to file this lawsuit because Defendant Dunn has continued to fail and refuse to grant or deny the power plant permit applications and issue the new power plant NPDES permits.

GENERAL ALLEGATIONS

56. Plaintiffs restate and incorporate by reference, as if fully set forth herein, paragraphs 1 through 55.

57. At all times relevant hereto, Defendant Dunn was required to comply with all applicable state and federal legal requirements concerning the NPDES permits.

58. Sovereign immunity is no defense to Plaintiffs' mandamus claim in this case.

59. The federal Clean Water Act ("CWA") prohibits the discharge of any pollutant, except in compliance with a NPDES permit issued under the Act. 33 U.S.C. § 1342(a).

60. NPDES permits impose limit on the discharge of pollutants, and establish related monitoring and reporting requirements, in order to improve the cleanliness and safety of the Nation's waters.

61. The CWA allows states to implement their own NPDES permit programs and Georgia has done so pursuant to the CWA, and the Georgia Water Quality Control Act ("GWQCA").

62. Thus, in Georgia, NPDES permits are issued by the GA DNR\EPD Director, upon a granted application pursuant to authority of the GWQCA and the federal CWA.

63. Georgia law requires at O.C.G.A. § 12-2-2(c)(1)(A) that:

> "[t]he director shall grant or deny any permit or variance within 90 days after receipt of all required application materials by the division, provided that the director may for any application order not more than one extension of time of not more than 60 days within which to grant or deny the permit or variance."

64. Both the CWA and the GWQCA require that NPDES permit durations be limited to a "fixed term" not exceeding five years. 33 U.S. Code § 1342(b)(1)(B); O.C.G.A. § 12-5-30(d)("fixed term set by the director *consistent with the federal Clean Water Act* of 1977, P.L. 95-217, as now or hereafter amended [. . .].")(emphasis supplied).

65. The purpose of the five year maximum time limit on NPDES permits is to insure that at intervals not greater than five years, the terms and conditions of a permit be subject to reevaluation by the U.S. EPA and the Georgia DNR\EPD, and that the

public have an opportunity to participate in this reevaluation. Costle v. Pacific Legal Foundation, 445 U.S. 198, 220 n.14, 100 S.Ct. 1095, 1108 n.14 (1980).

66. Accordingly, the five-year limit on an NPDES permit's maximum duration establishes an expiration date at which the permit must be reviewed and updated to reflect changes in the law, the conditions of receiving waters waters, or the requirements applicable to the permittees.

67. NPDES permits issued for less than the maximum five-year period may be continued or extended up to—but not beyond—the five-year maximum time limit. Costle v. Pacific Legal Foundation, 445 U.S. 198, 210 n.10, 100 S.Ct. 1095, 1103 n.10 (1980).

68. Referring specifically to NPDES permits, the GWQCA requires at O.C.G.A. § 12-5-30(d) that

> "[u]pon expiration of such permit, a new permit may be issued by the director after review by him in accordance with such guidelines as he shall prescribe; after notice and opportunity for public hearing; and upon condition that the discharge meets or will meet, pursuant to any schedule of compliance included in such permit, all applicable water quality standards, effluent limitations, and all other requirements established pursuant to this article."

69. In Georgia, effluent limitations required as conditions of NPDES permits must be achieved in the shortest reasonable period of time consistent with state law and the federal CWA. O.C.G.A. § 12-5-30(c).

70. When an existing NPDES permit expires, whether a new NPDES permit is issued pursuant to O.C.G.A. § 12-5-30(d), is a matter of public interest.

71. When an existing NPDES permit expires, whether a new NPDES permit is issued pursuant to O.C.G.A. § 12-5-30(d), can affect the rights of third persons.

72. Upon information and belief, Georgia DNR\EPD received all the required NPDES permit application materials needed to issue a new NPDES permit for Plant Bowen, more than one hundred eighty days (>180) before the Plant Bowen permit's June 30, 2012 expiration date.

73. Upon information and belief, Georgia DNR\EPD received all the required NPDES permit application materials needed to issue a new NPDES permit for Plant Hammond, more than one hundred eighty days (>180) before the Plant Hammond permit's June 30, 2012 expiration date.

74. Upon information and belief, Georgia DNR\EPD received all the required NPDES permit application materials necessary to issue a new NPDES permit for Plant McIntosh, more than one hundred eighty days (>180) before the Plant McIntosh permit's May 31, 2004 expiration date.

75. Upon information and belief, Georgia DNR\EPD received all the NPDES permit application materials necessary to issue a new NPDES permit for Plant Scherer, more than one hundred eighty days (>180) before the Plant Scherer permit's November 30, 2006 expiration date.

76. Upon information and belief, Georgia DNR\EPD received all the NPDES permit application materials necessary to issue a new NPDES permit for

Plant Wansley, more than one hundred eighty days (>180) before the Plant Wansley permit's August 31, 2011 expiration date.

77. The Georgia Water Quality Control Act, O.C.G.A. § 12-5-20 *et seq.*, does not allow the EPD Director to continue or extend NPDES permits beyond the expiration date of a maximum 5-year fixed term.

78. The Georgia Water Quality Control Act, O.C.G.A. § 12-5-20 *et seq.*, does not allow the EPD Director to continue or extend NPDES permits for an indefinite term with no fixed expiration date.

79. The federal Clean Water Act, 33 USC §§ 1251 et. seq., does not allow the EPD Director to continue or extend NPDES permits beyond the expiration date of a maximum 5-year fixed term.

80. The federal Clean Water Act, 33 USC §§ 1251 et. seq., does not allow the EPD Director to continue or extend NPDES permits for an indefinite term with no fixed expiration date.

MANDAMUS

81. Plaintiffs restate and incorporate by reference, as if fully set forth herein, paragraphs 1 through 80.

82. Defendant Dunn has a clear and non-discretionary public duty under O.C.G.A. § 12-2-2(c)(1)(A), to grant or deny any permit application within the time specified by O.C.G.A. § 12-2-2(c)(1)(A), and to issue new NPDES permits in accordance with O.C.G.A. § 12-5-30(d).

83. In failing to carry out his duty, Defendant Dunn deprives Plaintiffs of rights secured them by the Constitution and laws of the United States and the Constitution and laws of the State of Georgia.

84. To the extent that Defendant Dunn has any discretion in discharging his obligation to grant or deny the NPDES permits within the time specified by O.C.G.A. § 12-2-2(c)(1)(A) and or to issue new NPDES permits in accordance with O.C.G.A. § 12-5-30(d), Defendant Dunn has grossly abused such discretion.

85. Pursuant to O.C.G.A. § 9-6-20 et seq., the grant or denial of these NPDES permits within the time specified by O.C.G.A. § 12-2-2(c)(1)(A), is an official public duty which must be faithfully performed by Defendant Dunn.

86. Pursuant to O.C.G.A. § 9-6-20 et seq., the issuance of new NPDES permits in accordance with O.C.G.A. § 12-5-30(d), is an official public duty which must be faithfully performed by Defendant Dunn.

87. Defendant Dunn's failure to discharge his public duties is the cause of a defect of legal justice as to Plaintiffs, due to the fact that there is no other specific legal remedy for the Plaintiffs' rights violated here by Defendant Dunn.

88. Plaintiffs have a clear right to have this Court order Defendant Dunn to grant or deny these NPDES permits within the time specified by O.C.G.A. § 12-2-2(c)(1)(A).

89. Plaintiffs have a clear right to have this Court order Defendant Dunn to issue new NPDES permits in accordance with O.C.G.A. § 12-5-30(d).

90. Plaintiffs have no legal remedy for Defendant Dunn's inaction other than mandamus.

91. Requiring that Defendant Dunn comply with O.C.G.A. § 12-2-2(c)(1)(A) and O.C.G.A. § 12-5-30(d), does substantial justice and is a benefit to the public.

92. Accordingly, Plaintiffs request that the Court grant mandamus nisi, and after hearing, issue mandamus absolute requiring Defendant Dunn to grant or deny of the above-identified NPDES permits.

93. True and correct copies of the notice letters Defendant received from Plaintiffs and their allies concerning the issues in this lawsuit, are attached to this verified Petition for Mandamus.

WHEREFORE, Plaintiffs respectfully pray that this Court:

[a] Issue summons and process, and that Defendant be served and required to answer this petition;

[b] Schedule a hearing in not less than ten (10) nor more than thirty (30) days from the date of service of this Petition, pursuant to O.C.G.A. § 9-6-27, wherein the parties appear and show cause why mandamus should not issue to compel Defendant Dunn to grant or deny these NPDES permit applications and issue new NPDES permits in accordance with O.C.G.A. § 12-5-30(d); and

[c] Grant Plaintiffs such other and further relief as this Court deems just and proper.

IN THE SUPERIOR COURT OF FULTON COUNTY
STATE OF GEORGIA

SIERRA CLUB, INC., ALTAMAHA RIVERKEEPER, INC., CHATTAHOOCHEE RIVERKEEPER, INC., COOSA RIVER BASIN INITIATIVE, INC., and SAVANNAH RIVERKEEPER, INC., Plaintiffs, v. RICHARD E. DUNN, *Director of the Environmental Protection Division of the State of Georgia Department of Natural Resources,* Defendant.	))))))))))))))	Civil Action File # 2017CV284719

VERIFICATION

COMES NOW Plaintiff Sierra Club, Inc., by and through its undersigned authorized representative, and swears or affirms that the "*FACTS*" set out in the Petition in the above-styled action are true and correct.

SIERRA CLUB, INC.

BY: [signature]

ITS: Deputy Regional Campaign Director

STATE OF Ohio
COUNTY OF Delaware

Nahaliel Karfer, appeared before me, a Notary Public in and for the above jurisdiction, on this 5th day of January 2017, and after being duly sworn, made this Verification, under oath.

[Affix Seal] MOLLIE A. BRANAM, NOTARY PUBLIC STATE OF OHIO

[signature: Mollie A. Branam]
Notary Public

My commission expires:

ROBERT B. JACKSON, IV, LLC
Attorney at Law
260 Peachtree Street - Suite 2200
Atlanta, Georgia 30303
rbj4law@gmail.com (404) 313-2039 Voice

8 November 2016

VIA ELECTRONIC MAIL AND
VIA CERTIFIED MAIL #7012 0470 0000 4864 4418
RETURN RECIEPT REQUESTED

Richard E. Dunn, Director
Environmental Protection Division
Georgia Department of Natural Resources
2 Martin Luther King Drive - Suite 1152
Atlanta, Georgia 30334

Re: **NOTICE OF INTENT TO SUE** Due to Failure to Grant or Deny NPDES Permit Applications for Coal Fired Power Plants Bowen, Hammond, McIntosh, Scherer, and Wansley and to Issue New NPDES Permits.

Director Dunn:

On behalf of my client the Sierra Club, Inc. and its allies, including the Altamaha Riverkeeper, Inc. and the Coosa River Basin Initiative, Inc. -- and pursuant to the requirements of the federal Clean Water Act and the State of Georgia Water Quality Control Act -- I am writing to request that you proceed immediately to grant or deny the National Pollutant Discharge Elimination System ("NPDES") permit applications submitted for the following coal-fired power plants: McIntosh (permit expired 5/31/2004), Scherer (permit expired 11/30/2006), Wansley (permit expired 8/31/2011), Bowen (permit expired 6/30/2012), Hammond (permit expired 6/30/2012).

These coal fired power plants currently discharge pollutants from point sources into waters of the United States and waters of the State of Georgia. We understand that applications for issuance of NPDES permits to replace these expired NPDES permits have been received by your office, and in response, the Georgia Environmental Protection Division Director has sent letters purporting to extend the expired permits until the new NPDES permit can be issued.

Nonetheless, Georgia law requires the EPD Director to grant or deny any permit application within 150 days of the receipt of the complete application (O.C.G.A. § 12-2-2(c)(1)(A)) and to issue new NPDES permits in accordance with O.C.G.A. § 12-5-30(d). Federal law and Georgia law require that NPDES permits have a fixed term with an expiration date of no more than 5 years after the date of issuance. 33 U.S.C. § 1342(b)(1)(B); O.C.G.A. § 12-5-30(d). Clearly, it is now well past the last date by which the EPD was required to grant or deny the NPDES permit application for each of these power plants.

Sierra Club notified your office by letter dated March 30, 2016 (copy attached) of the need for immediate action regarding these expired coal-fired power plant NPDES permits. Sierra Club representatives met with your Water Branch Chief James Capp on July 8, 2015, and with you on

September 15, 2016. At their meeting with you, they provided copies of the attached letter, and at both meetings they wanted to ensure your office had notice of these expired permits and the need for immediate action. To date, there appears to still be no action on these NPDES permit applications.

Your inaction on permit applications constitutes a failure to faithfully perform your mandatory statutory duties, and constitutes gross negligence in the performance of those duties.

As a practical matter, permit updates are needed to incorporate improvements in pollution control technology, and to address developments in the regulatory landscape, and to allow opportunity for public comment. Under the Effluent Limitation Guidelines or ELGs,[1] for example, coal-fired power plants such as those listed above are required to greatly reduce their discharges of toxic water pollutants—particularly mercury, arsenic, and selenium—by November 2018. Georgia law requires that such effluent limitations be achieved in the shortest reasonable period of time. O.C.G.A. § 12-5-30(c). Your failure to grant or deny the permit applications as required by law, illegally risks delaying compliance with the ELGs. Moreover, it places communities in Georgia at risk. For example, according to EPA's Toxics Release Inventory, Plant Hammond generated nearly 300,000 pounds of toxic water pollutants in 2015 alone. During the same period, Plant Wansley generated nearly 600,000 pounds of such toxic water pollutants, and Plant Scherer generated a whopping 2 *million* pounds of toxic water pollutants.[2] The outdated and expired NPDES permits are woefully inadequate to ensure that the fate of these toxic pollutants is documented, or that the public is protected as the law requires.

Our strong preference would be that you grant or deny the NPDES permit applications without the need for us to resort to litigation, but the Sierra Club and its allies intend to file suit immediately if your office continues to fail and refuse to comply with the law.

Sincerely,

Robert B. Jackson, IV
Attorney for Sierra Club

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[1] U.S. EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015), codified at 40 C.F.R. part 423

[2] U.S. EPA, TRI On-site and Off-site Reported Disposed of or Otherwise Released (in pounds), all 16 facilities, for facilities in NAICS 2211 - Electric Utilities, for All chemicals, Georgia, 2015, *available at* http://tinyurl.com/hsyuh4q.

March 30, 2016

Judson Turner
Director, Georgia Environmental Protection Division

Audra Dickson
Chief, Wastewater Industrial Permitting Unit

Georgia Department of Natural Resources
Environmental Protection Division
2 Martin Luther King Jr. Drive
Suite 1152, East Tower
Atlanta, GA 30334

Re: *Incorporating the Effluent Limitation Guidelines for Steam Electric Power Plants into Outstanding NPDES Permits for Georgia's Coal-Fired Power Plants*

Dear Director Turner and Chief Dickson,

On behalf of our thousands of supporters and members across the state, we write to you now because of the numerous coal-fired power plants in Georgia whose National Pollutant Discharge Elimination System ("NPDES") permits are both expired and in need of revisions to address requirements under the updated Effluent Limitation Guidelines ("ELGs") for steam electric power plants. As explained in more detail below, these permits lag woefully behind what is necessary to protect rivers and drinking water in the state from mercury, arsenic, and other dangerous pollutants. The undersigned groups and our Georgia members therefore urge you to take action to:

1. Promptly issue draft NPDES permits and fact sheets for Georgia coal-fired power plants to require these plants to comply with the ELGs by November 1, 2018, unless you conclude that a later date is appropriate based on a well-documented justification that is consistent with regulatory guidance and with the public interest in securing vital water protections as soon as possible.

2. Take public comment for no less than 60 days on draft NPDES permits and fact sheets for Georgia coal-fired power plants that include compliance determinations for the ELGs.

3. Work with public health groups, environmental organizations, and other stakeholders, along with Georgia coal-fired power plant operators and fellow regulators to determine compliance obligations and timelines for other applicable regulatory requirements.

We urge you to take action now to resolve these issues, and request the opportunity to meet with you to discuss a way forward.

I. EDP Must Promptly Issue Draft NPDES Permits and Fact Sheets for Georgia's Coal-Fired Power Plants Incorporating the ELGs by the "As Soon As Possible" Compliance Deadline of November 2018.

On November 3, 2015, the U.S. Environmental Protection Agency ("EPA") published its updated ELGs for steam electric power plants, addressing decades' worth of advances in water quality science and control technology.[1] Notably, "[t]he final rule establishes the first nationally applicable limits on the amount of toxic metals and other harmful pollutants that steam electric power plants are allowed to discharge in several of their largest sources of wastewater."[2] In particular, these updated ELGs impose stringent technology-based effluent limitations on new and existing discharges of several common waste streams at coal-burning power plants, including fly and bottom ash transport water, and wastewater from flue gas desulfurization ("FGD") systems.[3] These updated regulations became effective on January 4, 2016, and must be incorporated into any NPDES permit issued after that date.[4]

As you are aware, NPDES permits have expired for all of Georgia's coal-fired power plants, which include:

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[1] U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,837 (Nov. 3, 2015), codified at 40 C.F.R. part 423.
[2] 80 Fed. Reg. at 67,838.
[3] *See* 40 C.F.R. § 423.13.
[4] 80 Fed. Reg. at 67,838, 67,883.

- Bowen (exp. 6/30/2012, owned by Georgia Power)
- Crisp (exp. 8/31/2010, owned by Crisp County Power Commission)
- Hammond (exp. 6/30/2012, owned by Georgia Power)
- McIntosh (exp. 5/31/2004, owned by Georgia Power)
- Scherer (exp. 11/30/2006, owned by Georgia Power)
- Wansley (exp. 8/31/2011, owned by Georgia Power)

NPDES permits have a maximum term of five years.[5] The limited permit duration and anti-backsliding requirements in the Clean Water Act aim to achieve continual progress towards restoring the nation's waters. As the D.C. Circuit has explained, "[t]he essential purpose of this series of progressively more demanding technology-based standards was not only to stimulate but to press development of new, more efficient and effective technologies."[6] As pollution control technologies improve, higher standards are incorporated into the NPDES permits of existing facilities upon renewal. <u>The timely renewal of NPDES permits is a linchpin of the Clean Water Act, and an essential part of your office's responsibilities</u>. Yet, as noted above, Georgia's coal plants are operating under permits that have been expired for roughly a full permit cycle, and in the case of McIntosh, over two permit cycles.

In light of the fact that updated ELGs applicable to these facilities are now in effect, the renewal NPDES permits for these facilities must reflect and incorporate the strengthened guidelines and standards. Prioritizing incorporation of the updated ELGs in these facilities' NPDES permits is especially necessary given the fact that the revised steam electric ELGs were promulgated to address the "outstanding public health and environmental problem" related to the discharge of waste streams containing toxic and other pollutants from coal-fired power plants.[7] Indeed, "[t]he steam electric ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date" and, as a result, current NPDES permits issued to these facilities under those previous, outdated ELGs "**<u>do not adequately control the pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years</u>**."[8] As such, in order to protect public health and the environment, those inadequacies must be rectified expeditiously.

Under the Clean Water Act, in issuing any renewal NPDES permit for Georgia's coal-fired power plants, the EDP "must incorporate these ELGs into NPDES permits as a floor or a minimum level of control."[9] Compliance with the ELGs must occur "as soon as possible beginning November 1, 2018, but no later than December 31, 2023."[10] For indirect dischargers, for whom the ELGs are self-implementing, compliance is required by November 1, 2018. To be clear, the

[5] *See* 33 U.S.C. § 1342(b)(1)(B).
[6] *Natural Res. Def. Council v. U.S. Envtl. Prot. Agency*, 822 F.2d 104, 124 (D.C. Cir. 1987).
[7] 80 Fed. Reg. at 67,840-41.
[8] 80 Fed. Reg. at 67,840 (emphasis added).
[9] 80 Fed. Reg. at 67,882.
[10] *See, e.g.*, 40 C.F.R. § 423.13(g)(1)(i) (establishing deadline for compliance with FGD wastewater standards; identical language appears in the provisions for other regulated waste streams).

phrase "as soon as possible" means November 1, 2018, and a later date is only permissible if absolutely necessary according to a set of specifically-enumerated factors spelled out in the ELGs.[11]

Indeed, for any extension beyond November 1, 2018, permitting authorities are to "provide a well-documented justification for how [they] determined the 'as soon as possible' date in the fact sheet or administrative record for the permit," and to "explain why allowing additional time to meet the limitations is appropriate," if that is the authority's conclusion.[12] Accordingly, any determination that a later date is appropriate must be well-documented and reflect consideration of the following factors:

- Time to expeditiously plan (including time to raise capital), design, procure, and install equipment to comply with the requirements of the final rule.[13] EPA further explains that "the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each waste stream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies."[14]

- Changes being made or planned at the plant in response to new or existing requirements at fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act.[15]

- For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.[16] EPA explains that the "record demonstrates that plants installing the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems."[17]

Any information that permittees provide to the permitting authority regarding any potential inability to comply by November 2018 should be made available to the public and subjected to close scrutiny and verification by your office.

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[11] 80 Fed. Reg. at 67,883; *see also* 40 C.F.R. § 423.11(t); *accord* 80 Fed. Reg. at 67,883, n.57 (observing that "[e]ven after the permitting authority receives information from the discharger," that supporting a request for a later compliance data "it still may be appropriate to determine that November 1, 2018, is 'as soon as possible' for that discharger.").
[12] *See* U.S. EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 2015), at p. 14-11 [hereinafter "TDD"].
[13] 40 C.F.R. § 423.11(t)(1).
[14] TDD at 14-11.
[15] 40 C.F.R. § 423.11(t)(2).
[16] 40 C.F.R. § 423.11(t)(3).
[17] TDD at 14-11.

The default November 1, 2018 compliance deadline is eminently achievable. The ELGs' administrative record conclusively demonstrates that the industry itself projects the total time needed for fly ash and bottom ash system retrofits to range from 27 to 36 months, from the start of conceptual engineering to final commissioning.[18] With appropriate planning and direction from state permitting authorities, many plants thus can and should be required to bring their operations into compliance by November 1, 2018, especially given that the updates to the ELGs were developed and thus anticipated by industry over several decades.

II. EPD Should Take Public Comment for No Less than 60 Days on Draft NPDES Permits and Compliance Determinations for the ELGs.

Because of the significance of the water protections in the ELGs and the findings you must make regarding the compliance deadlines, as discussed above, we urge you to revise and issue NPDES renewal permits for the above facilities with expired NPDES permits in light of the new standards and requirements, and to take public comment for no less than 60 days on the draft permits. Doing so is consistent with EDP's oversight responsibilities and commitment to public involvement.[19]

III. EPD Should Do Its Part to Protect Consumers from Piecemeal Regulatory Compliance Decisions that Fail to Identify and Pursue Cost-Effective Alternatives to Expensive Retrofits for Georgia's Aging Coal-Fired Plants.

The need to expeditiously issue NPDES permits for those coal-fired plants with expired permits issued under the previous, outdated ELGs is underscored by the fact that the owners and operators of the coal-fired power plants listed above, as well as your fellow state regulators, face complex and fast-approaching deadlines under numerous public health and environmental statutes which, together, will compel decisions about the prudency of continuing to operate these facilities. Clarity regarding the ELG compliance obligations and timelines will help ensure well-informed decisions that are in Georgians' best interests. Making prompt compliance determinations will allow fellow regulators to assess whether it is more prudent to retire—rather than spending huge sums of public monies to retrofit—these aging coal plants in light of the rapidly evolving regulatory and market conditions surrounding coal and carbon. EPD should do its part to protect consumers from piecemeal regulatory compliance decisions that fail to identify and pursue cost-effective compliance pathways.

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[18] Utility Water Act Group, *Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling, Attach 13: Retrofitting Dry Fly Ash Handling.
[19] *See* Georgia Environmental Protection Division, Mission, Vision, and Guiding Principles, *at* https://epd.georgia.gov/mission-vision-and-guiding-principles (noting EPD's vision of environmental protection as "serv[ing] the public by implementing state laws, rules, and policies to protect human health and the environment" and doing so in "a consistent, fair, and timely manner.")

In sum, we urge you to promptly revise and issue NPDES renewal permits and fact sheets for the above facilities with expired NPDES permits that incorporate the updated ELGs and contain your determination regarding the date upon which these facilities can comply with the ELGs. Prompt compliance with the ELGs is necessary in order to ensure that Georgia achieves and maintains compliance with water quality standards, improves drinking water quality, and otherwise protects the public and environment. Due to the complexity and novelty of the issues presented, we ask that you take public comment for no less than 60 days on those draft permits. Finally, we urge you to work with fellow regulators so that ELG compliance is not considered in isolation, but rather within the full suite of applicable regulations.

Given the number of permit updates required, we would like to request a meeting to discuss permit prioritization and finalization timelines. We appreciate your attention to this crucial matter and look forward to discussing this issue with you in the near future.

Sincerely,

/s/

Zachary M. Fabish
Staff Attorney
Sierra Club
50 F Street, NW - 8th Floor
Washington, DC 20001
(202) 675-7917
zachary.fabish@sierraclub.org

cc:

Judson H. Turner, Director, Environmental Protection Division

Molly Davis, Chief, NPDES Permitting Section, U.S. EPA Region 4

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Street, Apt. No.; or PO Box No. 2 MLK DR - STE 1152
City, State, ZIP+4 ATLANTA, GA 30334

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Richard E. Dunn, Director
Environmental Protection Division
Georgia Department of Natural Resources
2 Martin Luther King Drive - Suite 1152
Atlanta, Georgia 30334

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A. Signature
X Pamela Hughes ☐ Agent ☐ Addressee

B. Received by (Printed Name) Pamla Hughes
C. Date of Delivery 11-14-2016

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PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

Respectfully submitted this 12th day of January 2017.

Robert Jackson, Esq. - Ga. Bar # 387750
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Attorneys for the Plaintiffs

IN THE SUPERIOR COURT OF FULTON COUNTY
STATE OF GEORGIA

SIERRA CLUB, INC., ALTAMAHA RIVERKEEPER, INC., COOSA RIVER BASIN INITIATIVE, INC., and SAVANNAH RIVERKEEPER, INC., Plaintiffs, v. RICHARD E. DUNN, *Director of the Environmental Protection Division of the State of Georgia Department of Natural Resources,* Defendant.	)))))))))))))	Civil Action File #

SUMMONS

TO THE ABOVE NAMED DEFENDANT:

You are hereby summoned and required to file with the clerk of said Court and serve upon the Plaintiffs' attorney, whose names and addresses are:

Robert Jackson, Esq.
ROBERT B. JACKSON, IV, LLC
260 Peachtree Street - Suite 2200
Atlanta, Georgia 30303

Hutton Brown, Esq.
GREENLAW, INC.
104 Marietta Street - Suite 430
Atlanta, Georgia 30303

an Answer to the Complaint which is herewith served upon you, within 30 days after service of this summons upon you exclusive of the day of service. If you fail to do so, Judgment by default will be taken against you for the relief demanded in the Complaint.

This 12th day of January, 2017

Clerk of Superior Court

By______________________________
Deputy Clerk

Exhibit PHM-6

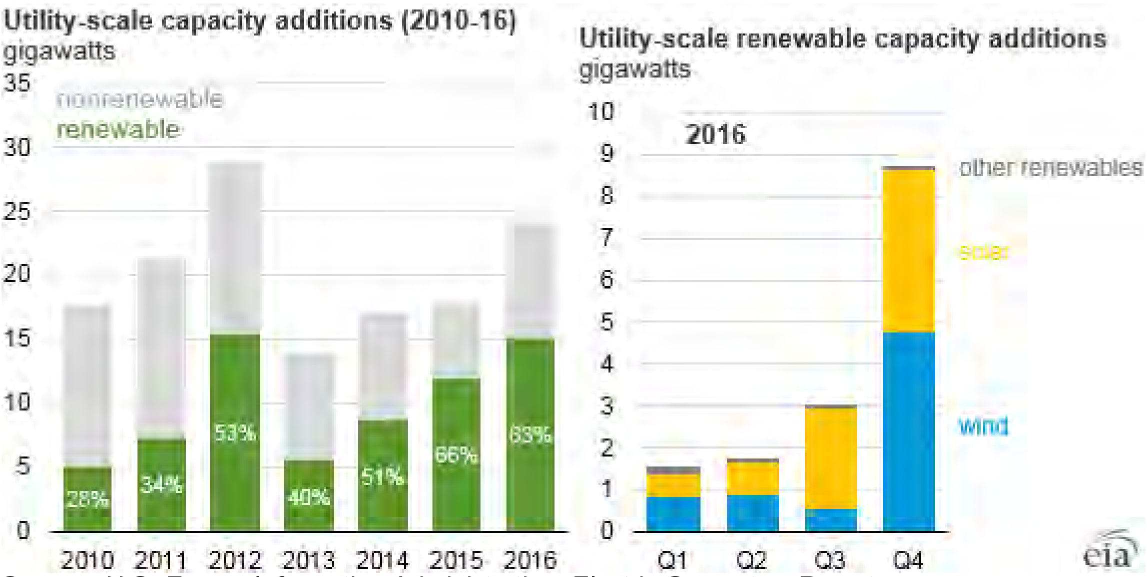
U.S. Energy Information Administration

Docket Nos. 160186-EI, 160170-EI
Direct Testimony of Sierra Club Witness Mosenthal
Exhibit PHM-6, Page 1 of 3

Today in Energy

January 10, 2017

Renewable generation capacity expected to account for most 2016 capacity additions



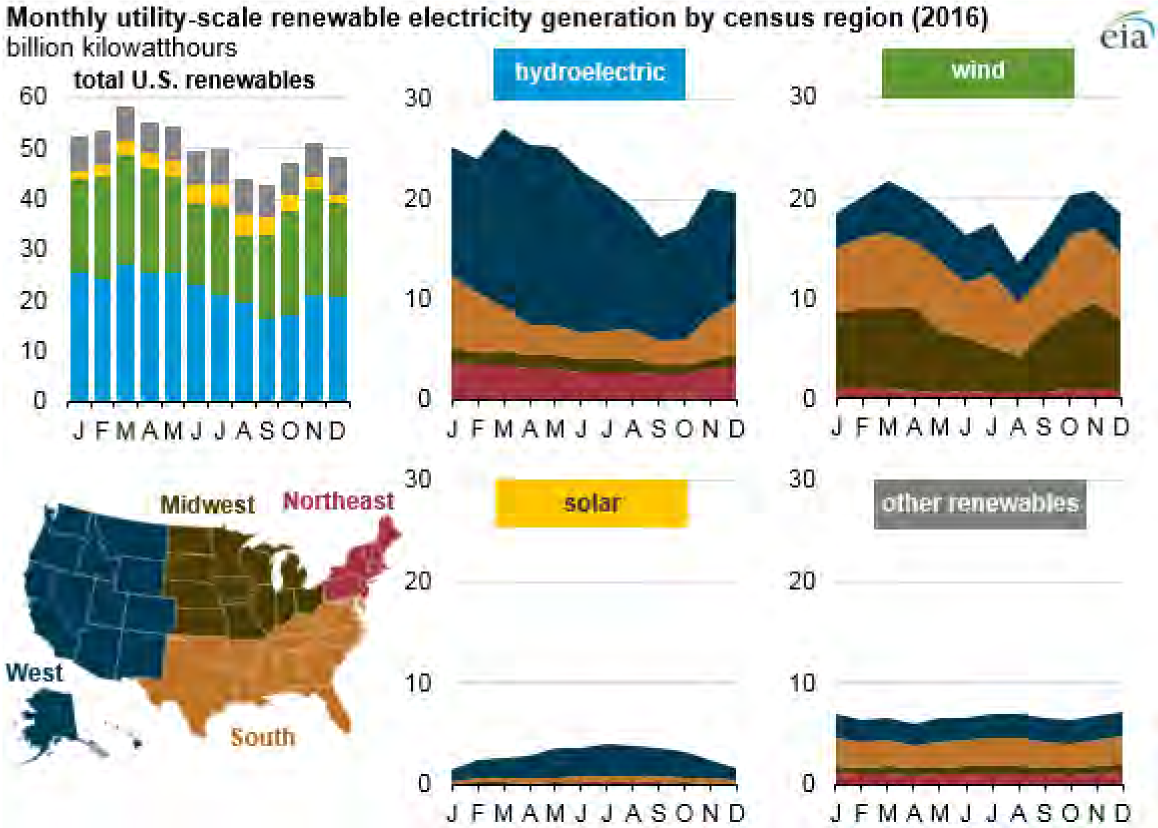
Source: U.S. Energy Information Administration, Electric Generators Report
Note: The last two months of 2016 are based on planned reported additions and are subject to change.

Once final data are in, EIA expects 24 gigawatts (GW) of new generating capacity to be added to the power grid during 2016. For the third consecutive year, more than half of these additions are renewable technologies, especially wind and solar.

Of the 2016 renewable additions, nearly 60% were scheduled to come online during the fourth quarter. Renewable capacity additions are often highest in the final months of the year, in part, because of timing qualifications for federal, state, or local tax incentives. Estimated fourth-quarter capacity additions for 2016 are based on planned additions reported to EIA and are subject to change based on actual project schedules.

Monthly U.S. renewable electricity generation peaked in March as high precipitation and melting snowpack led to a monthly peak in hydroelectric generation and strong wind resources led to a monthly peak in wind generation. Most renewable generation comes from the Western census division, which accounted for the majority of the hydroelectric (63%) and solar (77%) generation in the United States in 2016. Wind generation was more evenly spread across the country with 37% occurring in the Midwest, 35% in the South, 24% in the West, and the remaining 4% in the Northeast.

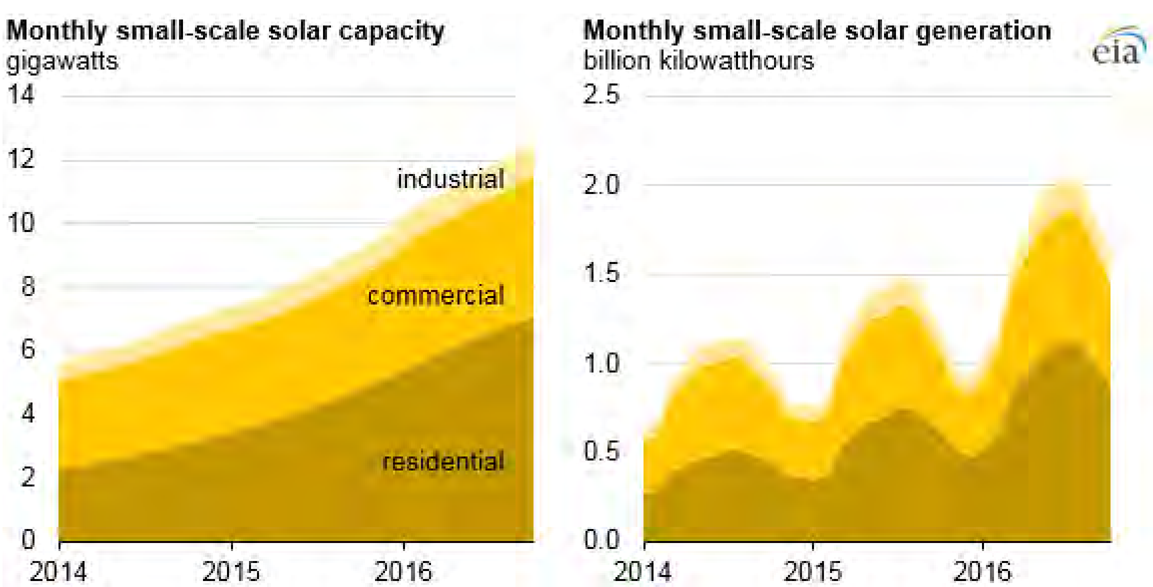
Docket Nos. 160186-EI, 160170-EI
Direct Testimony of Sierra Club Witness Mosenthal
Exhibit PHM-6, Page 2 of 3



Source: U.S. Energy Information Administration, Monthly Energy Review and Short-Term Energy Outlook
Note: The last two months of 2016 are projections and are subject to change.

At the end of 2015, EIA began publishing monthly estimates for distributed small-scale solar photovoltaic (PV) (one megawatt or less) capacity and generation. As of October 2016, the United States had a total of 12.6 GW of small-scale solar PV installed. Of this capacity, 56% was in the residential sector, 36% in the commercial sector, and 8% in the industrial sector. Monthly generation from small-scale solar PV peaked in July at 2.1 billion kilowatthours (kWh).

The distinction between capacity and generation shares is important to recognize. Because non-dispatchable technologies such as wind and solar facilities generate power only to the extent those respective resources are available, their capacity factors are typically lower than those of other resources.



Source: U.S. Energy Information Administration, Monthly Electric Utility Sales and Revenue

Other renewable electricity highlights in 2016

- The production tax credit (PTC) for wind and the solar investment tax credit (ITC) were extended at the end of 2015. The tax credits include an eventual decline in value for both technologies with the PTC for wind expiring in 2020 and the ITC for large-

scale solar declining from 30% to a permanent 10% and expiring for residential projects in 2022.
- New York, Oregon, and the District of Columbia extended and expanded their mandates for renewable electric generation to reach 50% of each state's total electricity generation by 2030, 2032, and 2040, respectively.
- Hydroelectric generation increased as drought conditions that affected hydroelectric generation on the West Coast in 2014 and 2015 diminished.

Principal contributor: Cara Marcy

Exhibit PHM-7

LBNL-1000917

Docket Nos. 160186-EI,
160170-EI
Direct Testimony of Sierra
Club Witness Mosenthal
Exhibit PHM-7, Page 1 of 49

Utility-Scale Solar 2014

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

Authors: Mark Bolinger and Joachim Seel

Lawrence Berkeley National Laboratory

September 2015

BERKELEY LAB

SunShot
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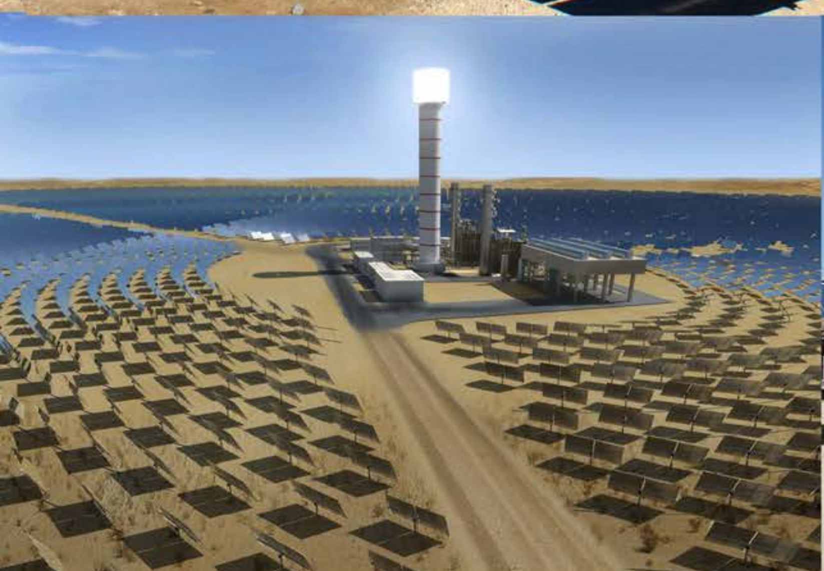


Utility-Scale Solar 2014

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

Authors: Mark Bolinger and Joachim Seel
Energy Analysis & Environmental Impacts Division, Lawrence Berkeley National Laboratory

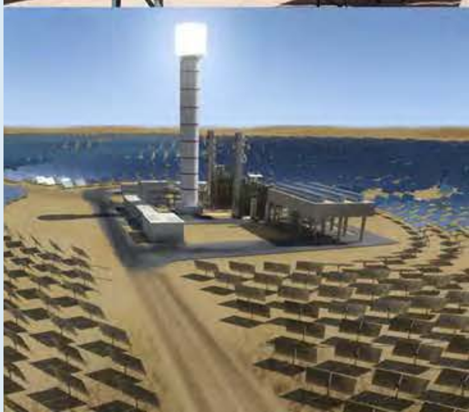


Table of Contents

List of Figures

List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
COD	Commercial Operation Date
CPV	Concentrated Photovoltaics
CSP	Concentrated Solar (Thermal) Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	Energy Information Agency
EPC	Engineering, Procurement & Construction
FERC	Federal Energy Regulatory Commission
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MW	Megawatt(s)
NCF	Net Capacity Factor
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PII	Permitting, Interconnection & Inspection
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SEGS	Solar Energy Generation Systems
TOD	Time-Of-Delivery

Executive Summary

Other than the nine Solar Energy Generation Systems ("SEGS") parabolic trough projects built in the 1980s, virtually no large-scale or "utility-scale" solar projects – defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar thermal power ("CSP") project larger than 5 MW_{AC} – existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in both 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a bit of a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including thermal storage – achieving commercial operation.

With this critical mass of new utility-scale projects now online and in some cases having operated for a number of years (generating not only electricity, but also empirical data that can be mined), the rapidly growing utility-scale sector is ripe for analysis. This report, the third edition in an ongoing annual series, meets this need through in-depth, annually updated, data-driven analysis of not just installed project costs or prices – i.e., the traditional realm of solar economics analyses – but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects in the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are presented where appropriate.

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

- ***Installation Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and price data analyzed later. For example, the use of tracking devices (overwhelmingly single-axis, though a few dual-axis tracking projects entered the population in 2014) continues to expand, particularly among thin-film (CdTe) projects, which had almost exclusively opted for fixed-tilt mounts prior to 2014. The quality of the solar resource in which PV projects are being built in the United States has increased on average over time, as most of the projects in the population (>90% in MW terms) are located in the Southwest where the solar resource is the strongest. That said, the market has also begun to expand outside of the Southwest, most notably in the Southeast. The average inverter loading ratio – i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating – has also increased among more recent project vintages, as oversizing the array can boost revenue, particularly when time-of-delivery pricing is used. In combination, these trends should drive AC capacity factors higher among more recently built PV projects (a hypothesis confirmed by the capacity factor data analyzed in Chapter 5). Finally, 2014 also saw three new large CSP projects – i.e., two 250 MW trough projects and one 377 MW solar power tower project – achieve commercial operation; in contrast, no new CPV plants came online in 2014.
- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by more than 50% since the 2007-2009 period, from around $\$6.3/W_{AC}$ to $\$3.1/W_{AC}$ (or $\$5.7/W_{DC}$ to $\$2.3/W_{DC}$, all in 2014 dollars) for projects completed in 2014. The lowest-priced projects among our 2014 sample of 55 PV projects were ~$\$2/W_{AC}$, with the lowest 20th percentile of projects having fallen considerably from $\$3.2/W_{AC}$ in 2013 to $\$2.3/W_{AC}$ in 2014.

The three large CSP projects that came online in 2014 were priced considerably higher than our PV sample, ranging from $5.1/W$_{AC}$ to $6.2/W$_{AC}$.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs appear to have been in the neighborhood of $20/kW$_{AC}$-year, or $10/MWh, in 2014. CSP O&M costs are higher, at around $40-$50/kW$_{AC}$-year. These numbers include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.

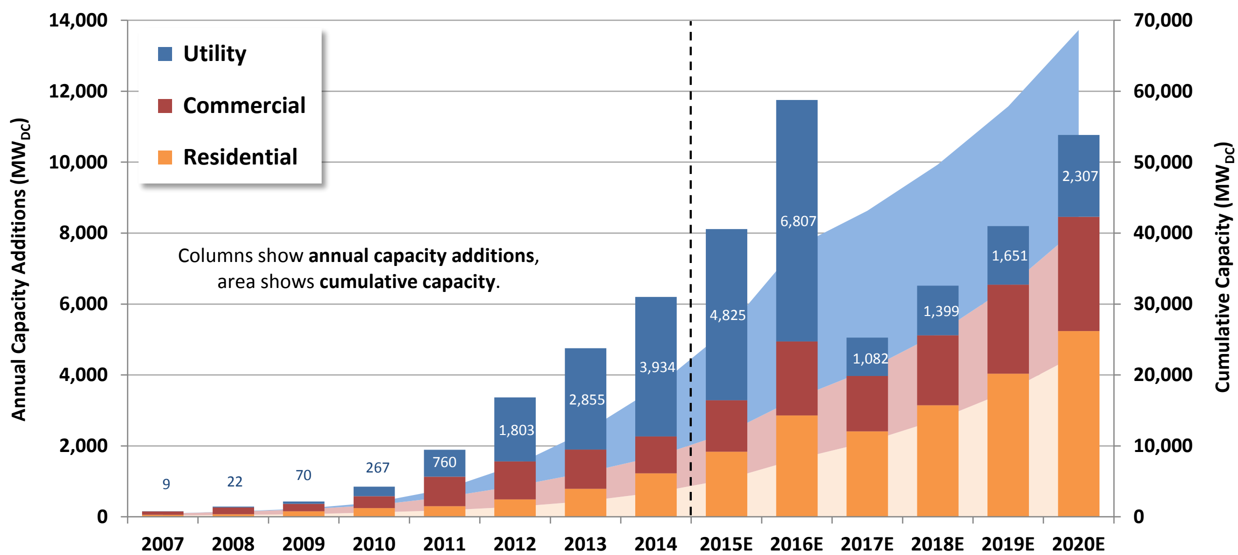
- ***Capacity Factors:*** The capacity-weighted average cumulative capacity factor across the entire PV project sample is 27.5% (median = 26.5% and simple average = 25.6%), but individual project-level capacity factors exhibit a wide range (from 14.8% to 34.9%) around these central numbers. This variation is based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site; whether the array is mounted at a fixed tilt or on a tracking mechanism; the inverter loading ratio; and the type of modules used (e.g., c-Si versus thin film). Improvements in the first three of these factors have driven capacity-weighted average capacity factors higher by project vintage over the last three years – e.g., 29.4% among 2013-vintage projects, compared to 26.3% and 24.5% for projects built in 2012 and 2011, respectively. In contrast, two of the new CSP projects built in recent years – a trough project with storage and a power tower project – generated lower-than-expected capacity factors in 2014, reportedly due to startup and teething issues. Performance has subsequently improved at both projects during the first six months of 2015 (compared to the same period in 2014). Likewise, the two CPV projects in our sample seem to be underperforming, relative to both similarly situated PV projects and ex-ante expectations.

- ***PPA Prices:*** Driven by lower installed project prices, improving capacity factors, and – more recently – the rush to build projects in advance of the scheduled reversion of the 30% investment tax credit ("ITC") to 10% in 2017, levelized PPA prices for utility-scale PV have fallen dramatically over time, by a steady ~$25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. Some of the most-recent PPAs in the Southwest have levelized PPA prices as low as (or even lower than) $40/MWh (in real 2014 dollars). At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a "fuel saver" alongside *existing* gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry through at least 2016. For example, at the end of 2014, there was at least 44.6 GW of utility-scale solar power capacity making its way through interconnection queues across the nation (though concentrated in California and the Southwest). Though not all of these projects will ultimately be built, presumably those that are built will most likely come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. Even if only a modest fraction of the solar capacity in these queues meets that deadline, it will still mean an unprecedented amount of new construction in 2015 and 2016 – as well as a substantial amount of new data to collect and analyze in future editions of this report.

1. Introduction

The term "utility-scale solar" refers both to large-scale concentrating solar power ("CSP") projects that use several different technologies to produce steam used to generate electricity for sale to utilities,[1] and to large photovoltaic ("PV") and concentrating photovoltaic ("CPV") projects that typically sell wholesale electricity directly to utilities, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets). Although utility-scale CSP has a longer history than utility-scale PV (or CPV),[2] and has recently experienced a bit of a renaissance,[3] the utility-scale solar market in the United States is now largely dominated by PV: there is currently significantly more PV than CSP capacity either operating (6.4x), under construction (30.5x), or under development (12.1x) in utility-scale projects (SEIA 2015). PV's dominance follows explosive growth in recent years: utility-scale PV has been the fastest-growing sector of the PV market since 2007, and since 2012 has accounted for the largest share of the overall PV market in terms of new MW installed (with 3,934 MW_{DC} of new capacity added in 2014 alone – see Figure 1), a distinction that is projected to continue through 2016 (GTM Research and SEIA 2015).[4]



Source: GTM/SEIA (2010-2015), Tracking the Sun Database

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

[1] Operating CSP projects most commonly use either parabolic trough or, more recently, power tower technology. CSP projects using other technologies, including compact linear Fresnel lenses and Stirling dish engines, have also been built in the United States, but largely on a pre-commercial prototype basis.
[2] Nine large parabolic trough projects totaling nearly 400 MW_{AC} have been operating in California since the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.
[3] More than twice as much CSP capacity came online in the United States in 2013/2014 as in the previous 28 years.
[4] GTM/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box – *Defining "Utility-Scale"* – in this chapter for a discussion of different definitions of "utility-scale"). In addition, the capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box – *AC vs. DC* – at the start of Chapter 2 discusses why AC capacity ratings make more sense than DC for utility-scale projects). Despite these two inconsistencies, the data are nevertheless useful for the basic purpose of providing a general sense for the size of the utility-scale market (both historical and projected) and demonstrating relative trends between market segments.

This rapidly growing utility-scale sector of the solar market is ripe for analysis. Historically, empirical analyses of solar economics have focused primarily on up-front installed costs or prices, and principally within the residential and commercial PV sectors (see, for example, Barbose and Darghouth 2015). 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), operation and maintenance ("O&M") costs, and power purchase agreement ("PPA") prices ($/MWh) – all data that are often unavailable publicly, and are also somewhat less meaningful,[5] within the residential and commercial sectors.

This report is the third edition in an ongoing annual series that, each year, compiles and analyzes the latest empirical data from the growing fleet of utility-scale solar projects in the United States. In this third edition, we maintain our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box below describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). Within this subset of solar 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 (78% of cumulative installed capacity), but CPV (<1%) and CSP (21%) projects are also included where useful data are available.

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

Data sources are diverse and vary by chapter depending on the type of data being presented, but in general include the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA"), state and federal incentive programs, state and federal

[5] 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, not only because of net metering and other state-level incentives that can affect the price, but also 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 electricity prices (this is known as "value-based pricing"). In contrast, utility-scale solar projects must often compete (policy incentives notwithstanding) for PPAs against other generating technologies within competitive wholesale power markets, and therefore tend to offer PPA prices that reflect the minimum amount of revenue needed to recoup the project's initial cost, cover ongoing operating expenses, and provide a normal rate of return (this is known as "cost-plus" pricing). Whereas cost-plus pricing data provide useful information about the amount of revenue that solar needs in order to be economically viable in the market, value-based PPA price data are somewhat less useful in this regard, in that they often reflect the "price to beat" more than the lowest possible price that could be offered.

regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. Sample size also varies by chapter, and not all projects have sufficiently complete data to be included in all data sets. All data involving currency are reported in constant or real U.S. dollars – in this edition, 2014 dollars[6] – and all PPA price levelization uses a 7% real annual discount rate.

Defining "Utility-Scale"

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

- Through its Form 860, the Energy Information Administration ("EIA") collects and reports data on all generating plants larger than 1 MW, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA ("GTM/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FIT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 20 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

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

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

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

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

[6] 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 2015*.

Finally, we note that this report complements several other related studies and ongoing research activities, all funded as part of the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020. For reference, this related work is briefly described in the text box below.

Related National Lab Research Products

Utility-Scale Solar is produced in conjunction with several related and ongoing research activities:

- ***Tracking-the-Sun*** is a separate annual report series produced by LBNL that focuses on residential and commercial solar and includes trends and analysis related to PV project pricing.

- ***The Open PV Project*** (openpv.nrel.gov) is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL) that incorporates data from *Tracking the Sun* and *Utility-Scale Solar*.

- ***Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*** is an annual briefing produced jointly by NREL and LBNL that provides a broad overview of PV pricing trends, based on ongoing research activities at both labs.

- ***In-Depth Statistical Analyses*** of PV pricing data by researchers at LBNL and several academic institutions seek to further illuminate PV pricing dynamics and the underlying drivers, using more-refined statistical techniques.

These and other solar energy publications are available at: **http://emp.lbl.gov/projects/solar**

2. Technology Trends Among the Project Population

Before diving into project-level data on installed prices, operating costs, capacity factors, and PPA prices, this chapter analyses trends in utility-scale solar project technology and configurations among the *entire population* of projects from which later data samples are drawn. This population consists of 209 ground-mounted PV, CPV and CSP projects, each larger than 5 MW_{AC} and with an aggregate capacity of 7,910 MW_{AC}, that had achieved full commercial operation within the United States by the end of 2014.[7] The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or price data presented and discussed in later chapters. As with the data samples explored in later chapters, the total project population is broken out and described here by technology type – first PV (including CPV) and then CSP. For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms, unless otherwise noted.

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current ("DC") terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current ("AC") capacity rating – measured by the combined AC rating of the project's inverters – is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar power, or "CSP") to which utility-scale PV is compared are described in AC terms – with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.

2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (described in more detail in this chapter, and portrayed in Figure 5). This increase in the "inverter loading ratio" boosts revenue and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the project's AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($/$W_{AC}$), operating costs ($/kW_{AC}-year), and AC capacity factor.

[7] With the exception of Chapter 6, which examines PPA prices for both online and planned projects, we do not include projects that have not yet achieved full commercial operation, unless multiple years lie between consecutive phases (in which case project development is more akin to the development of separate projects). One implication of this approach is that projects are attributed in their entirety to the year in which their last phase comes online, even though they may have been under construction (and even partially operating) for several years. We chose this approach because certain important project characteristics (such as project prices) are usually only reported for a project as a whole, rather than for its individual phases.

PV (194 projects, 6,236 MW_{AC})

At the end of 2014, 194 PV projects totaling 6,236 MW_{AC} were fully online in the United States and met the definition of utility-scale used in this report (ground-mounted and larger than 5 MW_{AC}).[8] These 194 projects, the first of which were installed in 2007, make up the total population of PV projects from which data samples are drawn in later chapters of this report. More than half of this capacity – i.e., 63 projects totaling 3,218 MW_{AC} – achieved commercial operation in 2014.

Figure 2 breaks out this capacity by module type and project configuration – i.e., projects that use crystalline silicon ("c-Si") versus thin-film modules,[9] and projects mounted at a fixed tilt instead of on a tracking device that follows the position of the sun.[10] Though thin-film modules powered two-thirds of the new utility-scale PV capacity installed in 2010, c-Si projects dominated in 2011, 2012, and 2013, accounting for 70% of all new utility-scale PV capacity installed in those three years. This trend reversed yet again in 2014, however, when the 6 largest projects built all used thin-film modules, resulting in a 70% market share.

Among the entire project sample that came online in 2014 (including both c-Si and thin-film projects) the number of projects using solar tracking technologies increased slightly from 55% in 2013 to 58% in 2014. In capacity terms, however, tracking projects decreased to 41% of new 2014 capacity (from 56% in 2013) as the three largest 2014 projects (Topaz, Agua Caliente and Desert Sunlight) all used fixed-tilt racking.

Notably, 12 of the 16 thin-film projects that came online in 2014 use single-axis tracking – a significant departure from just 2 tracking thin-film projects built prior to 2014. This shift is largely attributable to First Solar's acquisition of RayTracker's single-axis tracking technology back in 2011; First Solar deployed this technology in all but its four largest projects in 2014.[11] Tracking has historically not been as common among thin-film projects, largely because the lower efficiency of thin-film relative to c-Si modules requires more land area per nameplate MW – an expense that is exacerbated by the use of trackers (that said, the efficiency of First Solar's CdTe modules has been increasing over time).

[8] Because of differences in how "utility-scale" is defined (e.g., see the text box on page 3), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM Research and SEIA 2015) of the amount of utility-scale PV capacity online at the end of 2014.

[9] Module manufacturer First Solar, which produces CdTe modules, accounts for all new thin-film capacity added to the project population in 2014.

[10] All but two of the PV projects in the population that use tracking systems use single-axis trackers (which track the sun from east to west each day). In contrast, two recently built PV projects in Texas, along with the two CPV projects and one CSP power tower project (described later), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental costs (and risk of malfunction), depending on the PPA price.

[11] The very large Topaz, Agua Caliente, and Desert Sunlight projects had all executed PPAs and were well under development (and perhaps even construction) prior to the acquisition of RayTracker. The large Antelope Valley project was in a similar position, but did manage to incorporate tracking in roughly 20% of the project.

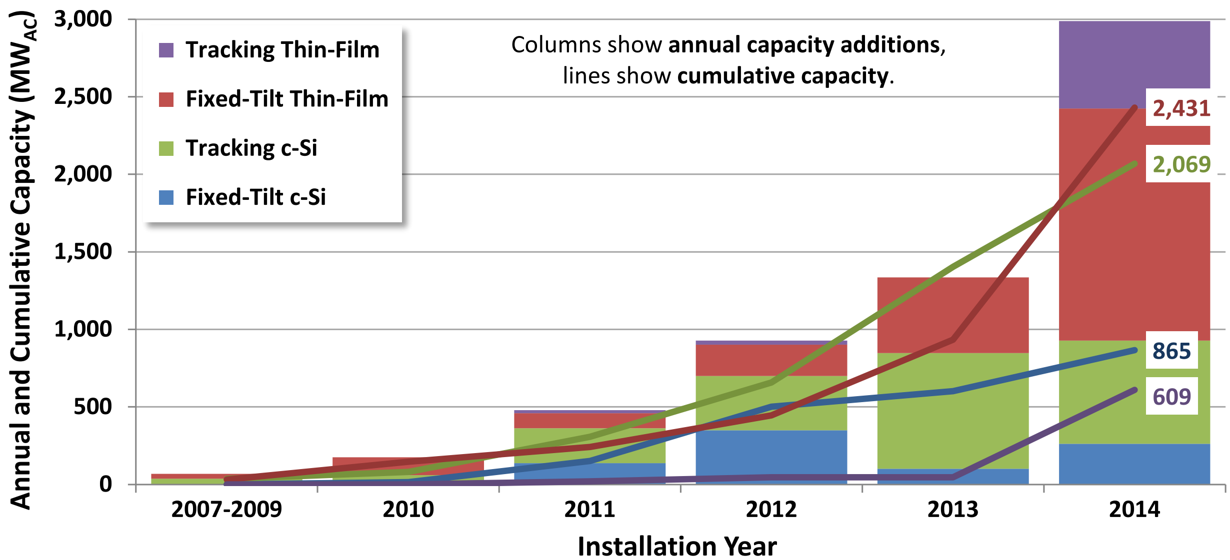


Figure 2. Capacity Shares of PV Module and Mounting Configurations by Installation Year

Figure 2 also breaks down the composition of *cumulative* installed capacity as of the end of 2014. Fixed-tilt thin-film (2,431 MW_{AC}) held a slight lead over tracking c-Si (2,069 MW_{AC}, but spread across more than twice as many projects), while fixed-tilt c-Si (865 MW_{AC}) and tracking thin-film (609 MW_{AC}) followed more distantly. Overall, the total project population as of the end of 2014 was split fairly evenly (in capacity terms) between fixed-tilt (55%) vs. tracking (45%) projects, and thin-film (53%) vs. c-Si projects (47%).

Figure 3 overlays the location of every utility-scale solar project in the LBNL population (including CPV and CSP projects) on a map of solar resource strength, as measured by global horizontal irradiance ("GHI").[12] Not surprisingly, most of the projects (and capacity) in the population are located in the southwestern United States,[13] where the solar resource is the strongest and where state-level policies (such as renewable portfolio standards, and in some cases state-level tax credits) encourage utility-scale solar development. As shown, however, utility-scale solar projects have also been built in various states along the east coast and in the Midwest, where the solar resource is not as strong; these installations have largely been driven by state renewable portfolio standards. Though there are obviously some exceptions, Figure 3 also shows a preponderance of tracking projects (both c-Si and, more recently, thin-film) in the high-GHI Southwest, compared to primarily fixed-tilt c-Si in the lower-GHI East.

[12] Global Horizontal Irradiance (GHI) is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance (DNI) and diffuse horizontal irradiance (DIF). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).
[13] As of the end of 2014, the Southwest (defined rather liberally here to include CA, NV, AZ, UT, CO, NM, and TX) accounted for 90% of the population's cumulative PV capacity, and 96% of its CSP capacity.

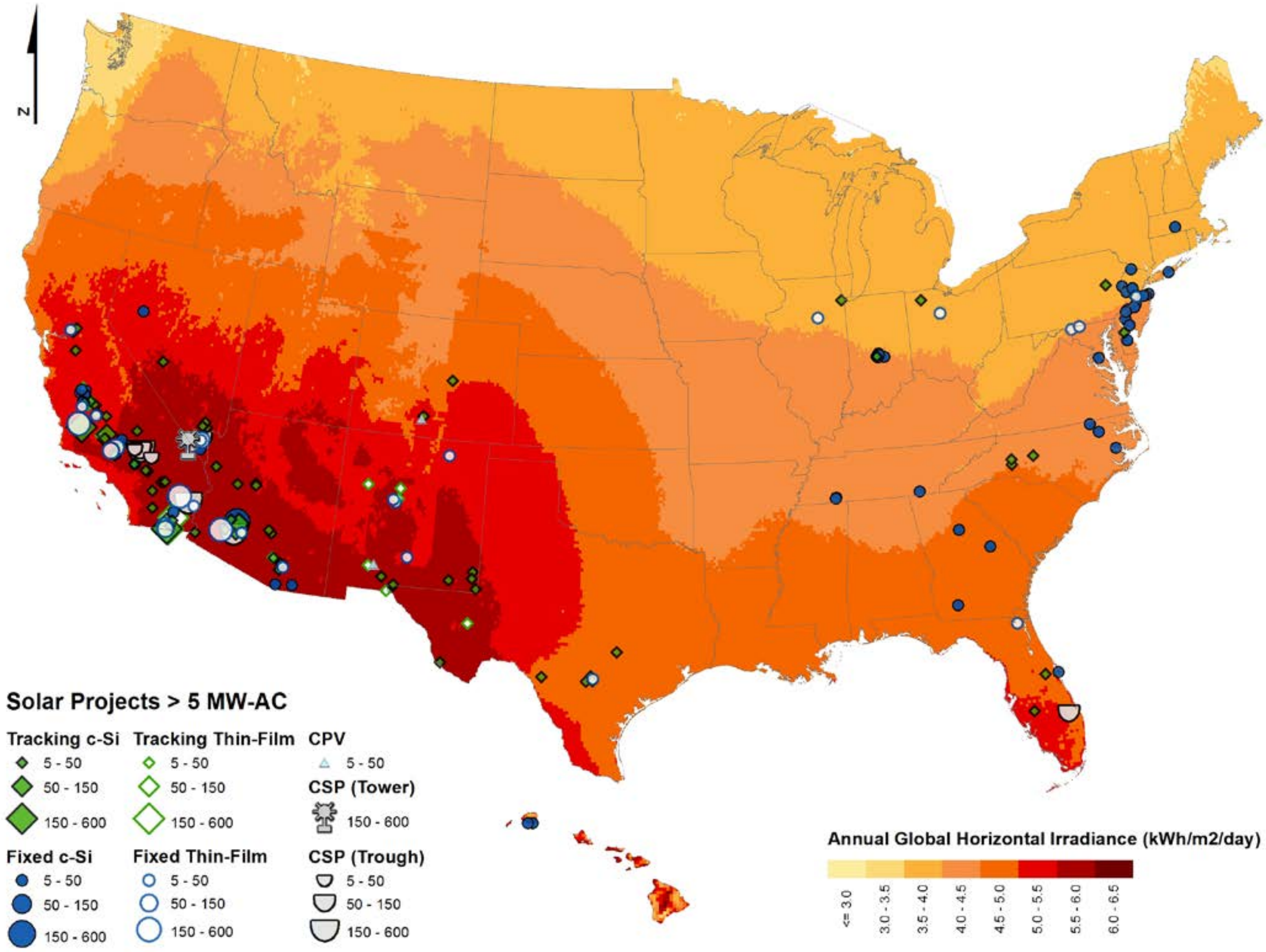


Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale Solar Project Locations

While Figure 3 provides a static view of *where* and in what type of solar resource regime utility-scale solar projects within the population are located, knowing *when* each of these projects was built – and hence how the average resource quality of the project fleet has evolved over time – is also useful, for example, to help explain any observed trend in project-level capacity factors by project vintage (explored later in Chapter 5).

Figure 4 addresses this question by showing the capacity-weighted average GHI (in kWh/m^2/day) among PV projects built in a given year, both for the entire PV project population (solid black line) and broken out by fixed-tilt vs. tracking projects. Across the entire population, the average GHI has increased steadily over time, suggesting a relative shift in the population towards projects located in the high-GHI Southwest. Although the capacity-weighted averages for fixed-tilt and tracking projects are not too dissimilar, the 20th percentiles are markedly different, with fixed-tilt projects stuck around 4 kWh/m2/day, in contrast to much higher (and generally increasing by vintage) 20th percentile values for tracking projects. The wide distribution of fixed-tilt projects reflects the fact that – as shown previously in Figure 3 – most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects are also present in the high-GHI Southwest (often using CdTe thin-film technology, perhaps due to its greater tolerance for high-temperature environments[14]). Tracking projects, meanwhile, are concentrated primarily in the Southwest.

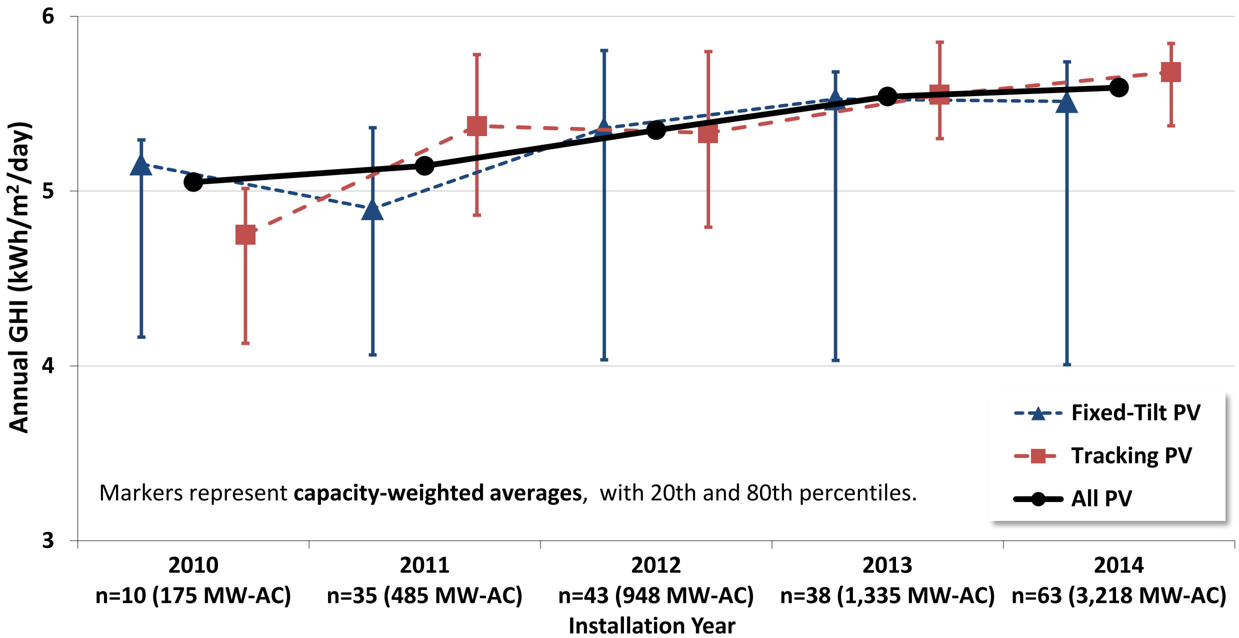


Figure 4. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

A second project-level characteristic that influences both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[15] With the cost of PV modules having dropped precipitously in recent years (and more rapidly than the cost of inverters), and with some utilities (particularly in California) offering time-varying PPA prices that favor generation during certain daylight hours, including late afternoon, many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which – like tracking – boosts the capacity factor,[16] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production

[14] The vast majority of thin-film capacity in the project population uses CdTe modules from First Solar. On its web site (First Solar 2015), 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 in the high-insolation Desert Southwest region.
[15] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). This report uses inverter loading ratio, or ILR.
[16] 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.

periods[17]). Particularly under time-varying PPA prices that extend peak pricing into the morning and/or evening hours, the resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to just the high-insolation summer months).

Figure 5 shows the capacity-weighted average ILR among projects built in each year, both for the total PV project population (solid black line) and broken out by fixed-tilt versus tracking projects. Across all projects, the average ILR has increased significantly over time, from around 1.2 for projects built in 2010 to 1.31 in 2013. In 2014, the capacity-weighted average declined slightly to 1.28, as a number of very large projects that had been under construction for several years finally came online; some of these projects have lower ILRs than their more-recently designed counterparts. But the 2014 median ILR (not shown) remained unchanged from 2013, at 1.29.

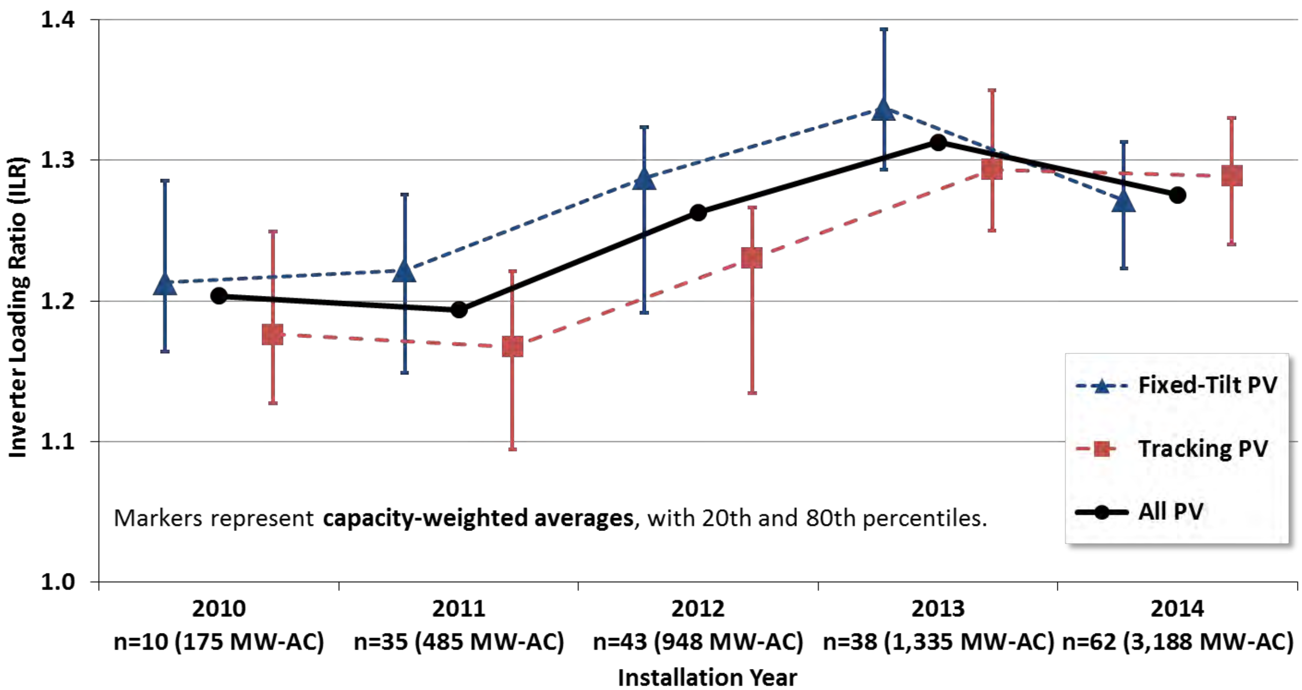


Figure 5. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

With the exception of 2014 (again, influenced by these few large fixed-tilt projects with lower ILRs), fixed-tilt projects generally feature higher ILRs than tracking projects. This finding is consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, "tracking-like" daily production profile.

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

All else equal, Figure 4 and Figure 5 suggest that project-level capacity factors should increase among more recently built PV projects. This hypothesis is explored further (and confirmed) in Chapter 5.

CSP (15 projects, 1,673 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough build-out in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida), and the 250 MW_{AC} Solana trough project in Arizona in 2013 (which also includes 6 hours of molten salt storage capacity).

In 2014, three additional CSP projects came online in California: two more trough projects without storage (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale “solar tower” project in the United States (Ivanpah at 377 MW_{AC}). A second 110 MW_{AC} solar tower project with 10 hours of built-in thermal storage – Crescent Dunes in Nevada – has finished major construction activities but, at the time of writing, was still in the commissioning phase and not yet commercially online, and is thus excluded from this report. In the wake of this unprecedented buildout – totaling 1,127 MW_{AC} – of new CSP capacity in the past two years, there are currently no other major CSP projects moving towards construction in the United States.

3. Installed Prices

This chapter analyzes installed price data from a large sample of the overall utility-scale solar project population described in the previous chapter.[18] Specifically, LBNL has gathered installed price data for 176 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) solar projects totaling 7,145 MW_{AC} and built between 2007 and 2014. The price sample is dominated by 170 PV projects (including 2 CPV projects) that total 5,874 MW_{AC} (i.e., PV accounts for 97% of all projects and 82% of all capacity in the installed price sample). It also includes 6 CSP projects totaling 1,270 MW_{AC}, consisting of the more recently built projects described in the previous chapter (rather than the older SEGS projects).

In general, only fully operational projects for which all individual phases were in operation at the end of 2014 are included in the sample[19] – i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2015 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent reductions in component costs or other changes in market conditions.[20] For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV (Feldman et al. 2015), and may differ from the average installed prices reported elsewhere (Bloomberg New Energy Finance 2015; Fu et al. 2015; GTM Research and SEIA 2015). A text box later in this chapter (see *Bottom-Up vs. Top-Down*) explores this issue in more detail.

This chapter analyzes installed price trends among the sample of utility-scale projects described above. It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by module type (c-Si vs. thin-film vs. CPV), mounting type (fixed-tilt vs. tracking), and system size. The chapter then provides an overview of installed prices for the six CSP projects in the sample. Sources of installed price information include the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, trade press articles, and data previously gathered by the National Renewable Energy Laboratory (NREL). All prices are reported in real 2014 dollars.

[18] 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 financing transaction), or alternatively the fair market value of a given project – i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.
[19] In contrast, later chapters of this report do present data for individual phases of projects that are online, or (in the case of Chapter 6 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.
[20] This reasoning may partially explain why the decline in installed prices presented in this chapter has seemingly not kept pace with the decline in PPA prices reported later in Chapter 6.

PV (170 projects, 5,874 MW_{AC}, including 2 CPV projects totaling 35 MW_{AC})

LBNL's sample of 170 PV (and CPV) projects totaling 5,874 MW_{AC} for which installed price estimates are available represents 87% of the total number of PV projects and 94% of the amount of capacity in the overall PV project population described in Chapter 2. Focusing just on those PV projects that achieved commercial operation in 2014, LBNL's sample of 55 projects totaling 3,052 MW_{AC} represents 87% and 95% of the total number of 2014 projects and capacity in the population, respectively.

Figure 6 shows installed price trends for PV (and CPV) projects completed from 2007 through 2014 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is often reported in $\$/W_{DC}$ terms as well (Barbose and Darghouth 2015; GTM Research and SEIA 2015). As noted in the text box (*AC vs. DC*) at the beginning of Chapter 2, however, this report analyzes utility-scale solar in AC terms. Figure 6 shows installed prices both ways (in both $\$/W_{DC}$ and $\$/W_{AC}$ terms) in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this chapter, however, as well as the rest of this document, report data exclusively in AC terms, unless otherwise noted.

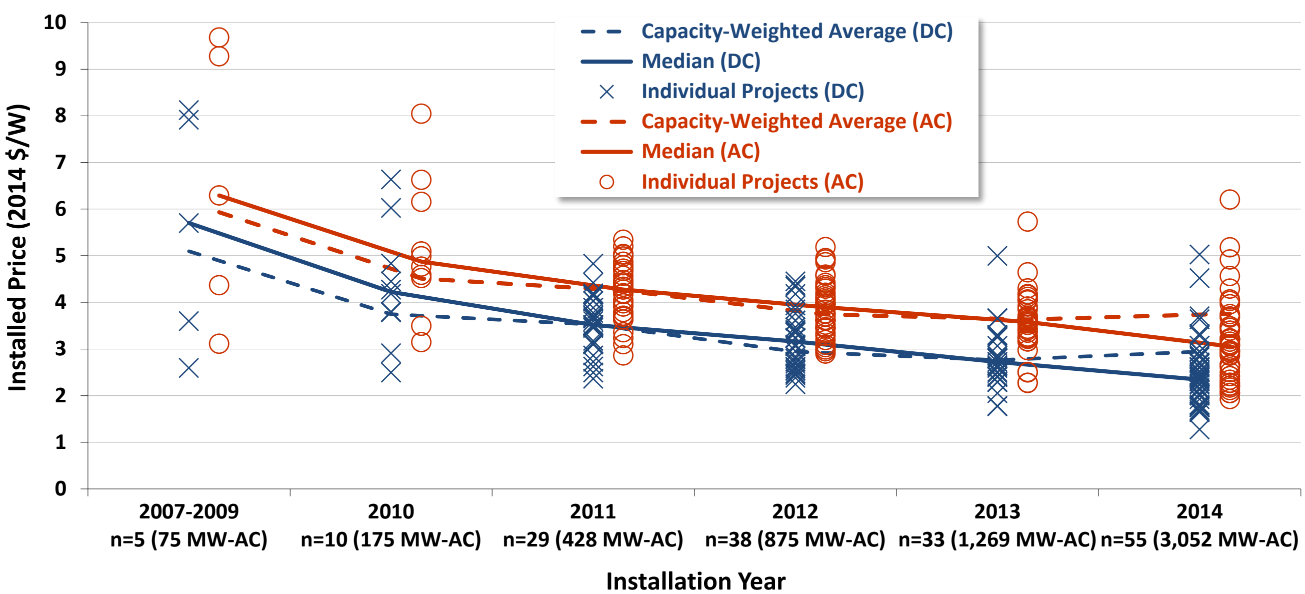


Figure 6. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

As shown, the median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $\$3.1/W_{AC}$ (or $\$2.3/W_{DC}$) in 2014. This represents a price decline of more than 50% since the 2007-2009 period (and 37% since 2010). The lowest-priced projects among our 2014 sample of 55 PV projects were ~$\$2/W_{AC}$, with the lowest 20^{th} percentile of projects having fallen considerably, from $\$3.2/W_{AC}$ in 2013 to $\$2.3/W_{AC}$ in 2014.

In contrast, capacity-weighted average prices (dashed lines) have declined more slowly through 2013, and even increased slightly in 2014 to $\$3.8/W_{AC}$ (or $\$2.9/W_{DC}$). The divergence between median and capacity-weighted average prices in 2014 can be explained by a number of very large PV projects that have been under construction for several years but that only achieved final commercial operation in 2014 (and so only entered our sample in 2014). These projects may have signed EPC contracts several years ago, perhaps at significantly higher prices than some of their smaller and more-nimble counterparts that started construction more recently.[21] Although in general we prefer capacity-weighted averages over medians,[22] the next graph will focus on medians rather than capacity-weighted averages in order to avoid the apparent distortion seen in Figure 6 for 2014.

While median prices in the sample have generally declined over time, there remains a considerable spread in individual project prices within each year. The overall variation in prices may be partially attributable to differences in module and mounting type – i.e., whether PV projects use c-Si or thin-film modules, and whether those modules are mounted at a fixed tilt or on a tracking system.

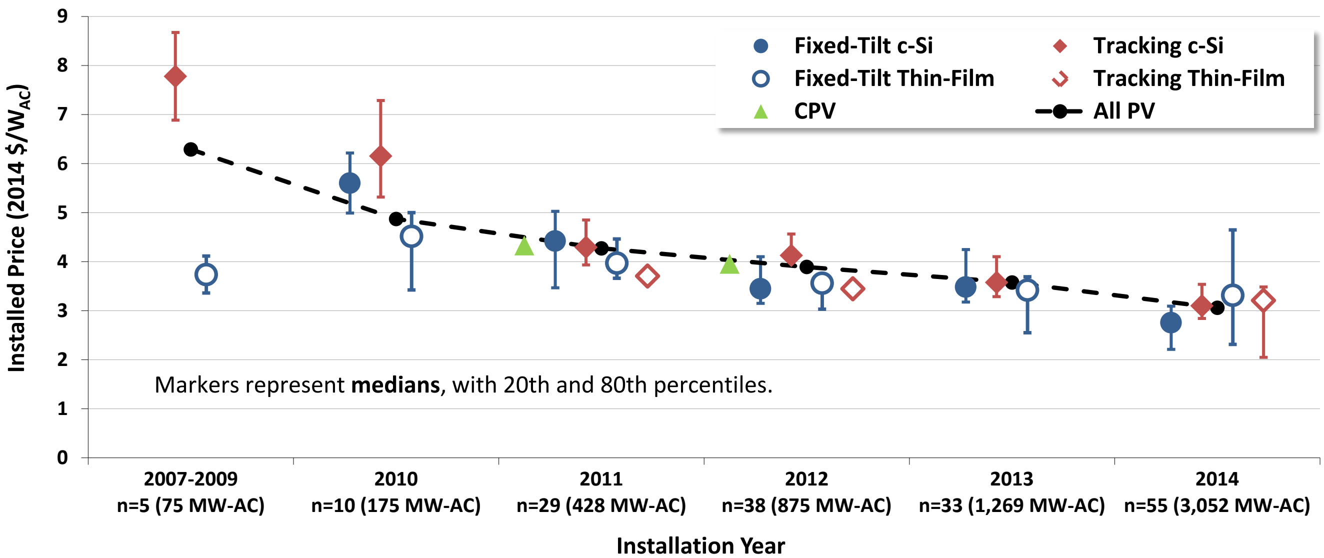


Figure 7. Installed Price of Utility-Scale PV and CPV Projects by Project Design and Installation Year

Figure 7 breaks out installed prices over time among these four combinations (and also includes the two CPV projects in the sample – but excludes several "hybrid" projects that feature a mix of

[21] For example, within our PPA price sample (described later in Chapter 6), the longest span between PPA execution date (as a proxy for EPC contract execution date) and commercial operation date for projects that came online in 2014 is 5 ¾ years, with the average lag for systems larger than 100 MW_{AC} being 3 ¾ years, compared to 2¼ years for systems smaller than 100 MW_{AC}. Because of their size, very large projects dominate the capacity-weighted average price in 2014 (eight projects larger than 100 MW_{AC} represent 74% of the capacity additions, but only 12.5% of new projects, in 2014).

[22] Whereas medians (and simple means) tell us about the typical project, capacity-weighted averages tell us more about the typical unit of capacity (e.g., the typical MW). Throughout most of this report, we are interested in analyzing the U.S. solar market in its entirety – e.g., deriving a representative installed price per unit of capacity (rather than per project), or a representative capacity factor or PPA price per MWh for the US fleet as a whole – and therefore tend to favor capacity-weighted averages over medians (or simple means). Given the apparent distortion noted above, however, as well as our increasing sample size over time (which lends itself more readily to medians), the use of medians seems more appropriate for this chapter – and will also align this report more closely with reported median prices for the residential and commercial PV systems in LBNL's companion *Tracking the Sun* series (e.g., see Barbose and Darghouth 2015).

module and/or mounting types, and so do not fit neatly into these four combinations). In 2014, the median price was $2.8/W_{AC}$ for fixed-tilt c-Si projects, $3.1/W_{AC}$ for tracking c-Si projects, $3.3/W_{AC}$ for fixed-tilt thin-film projects, and $3.2/W_{AC}$ for tracking thin-film projects.

Trends of particular note include:

- Although projects using c-Si modules were more expensive than projects using thin-film modules (e.g., by ~$1.1/W_{AC}$ on average in 2010 for fixed-tilt projects), the average installed price of fixed-tilt c-Si and thin-film projects has converged over time, and even reversed in 2014 when c-Si held a ~$0.6/W_{AC}$ advantage over thin-film projects completed in the same year (although some smaller fixed-tilt thin-film projects are offered at prices similar to the cheaper c-Si projects). This convergence has been led by the falling price of c-Si modules over time. As the price of c-Si projects has converged with thin-film, the predominance of c-Si projects has grown in both the installed price sample and the broader population (although this is not necessarily true for total interconnected capacity, given several very large thin-film projects that came online in 2014).

- Tracking systems remain slightly more expensive than fixed-tilt systems within the sample – a difference of about $0.3/W_{AC}$ in 2014 among c-Si projects. As shown later in Chapter 5, however, this higher up-front expenditure results in greater energy production. In contrast, fixed-tilt thin-film projects do not appear to have a similar cost advantage over tracking thin-film projects, though this may be attributable to the previously noted price lags associated with several very large fixed-tilt thin-film projects (as well as perhaps to the vertical integration of First Solar and RayTracker).

- The two high-concentration CPV projects built in 2011 and 2012 exhibit installed prices that are comparable to the average PV pricing in the sample (yet, as shown later in Chapter 5, these two CPV projects have not performed as well as the average PV project). One or more low-concentration CPV projects (e.g., SunPower's new C7 technology powering an Apple server farm in Nevada) will enter the sample in 2015, providing additional data points.

Differences in project size may also explain some of the variation in installed prices, as PV projects in the sample range from 5.1 MW_{AC} to 585 MW_{AC}. Figure 8 investigates price trends by project size. To minimize the potentially confounding influence of price reductions over time, Figure 8 focuses on just those PV projects in the sample that became fully operational in 2014.

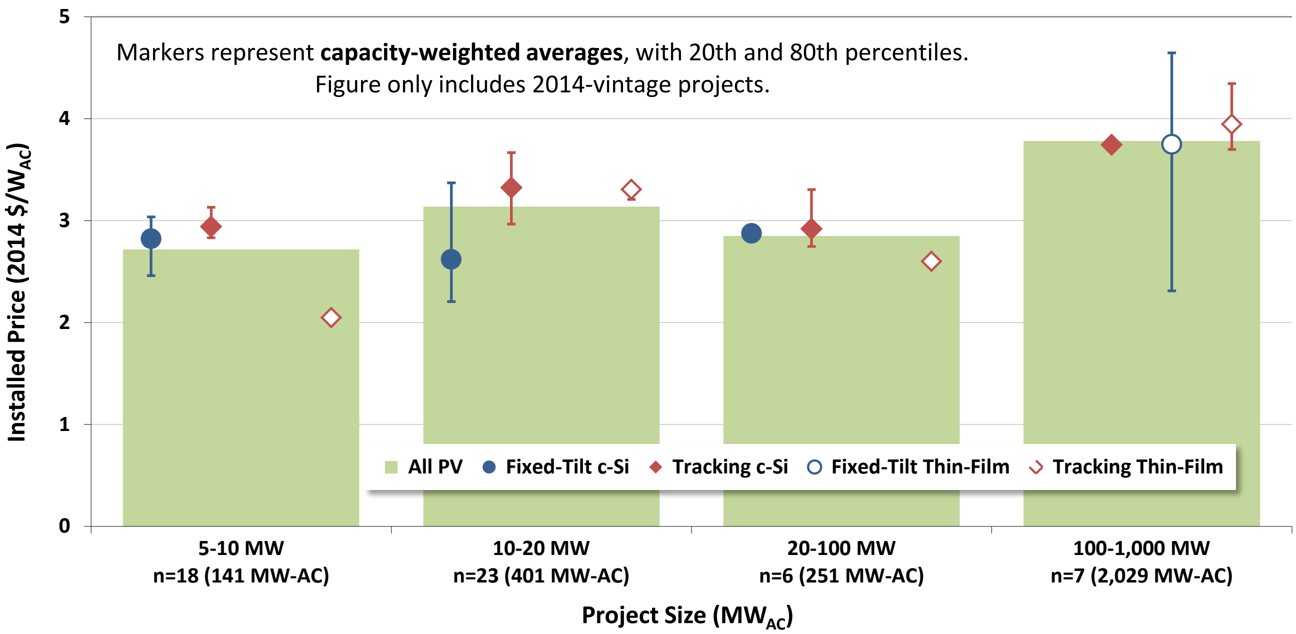


Figure 8. Installed Price of 2014 PV Projects by Size and Project Design

As shown, no consistent evidence of economies of scale can be found among the PV systems in our pricing sample that achieved commercial operation in 2014.[23] For example, there are no clear trends – either among the various mounting/module combinations (e.g., fixed-tilt c-Si) or for all projects in aggregate – among the first three project size bins shown in Figure 8, which range from 5 MW_{AC} up to 100 MW_{AC}. One possible explanation for this lack of trend is that economies of scale may be limited primarily to projects smaller than 5 MW_{AC} – which are excluded from our sample – given that the standardized and modular "power blocks" of module manufacturers like SunPower and First Solar are sized below this 5 MW_{AC} threshold. Another possibility is potential inconsistency in what costs or prices are captured among projects; e.g., some of the larger projects may include interconnection and transmission costs that are not present (or at least not reported) for smaller projects.

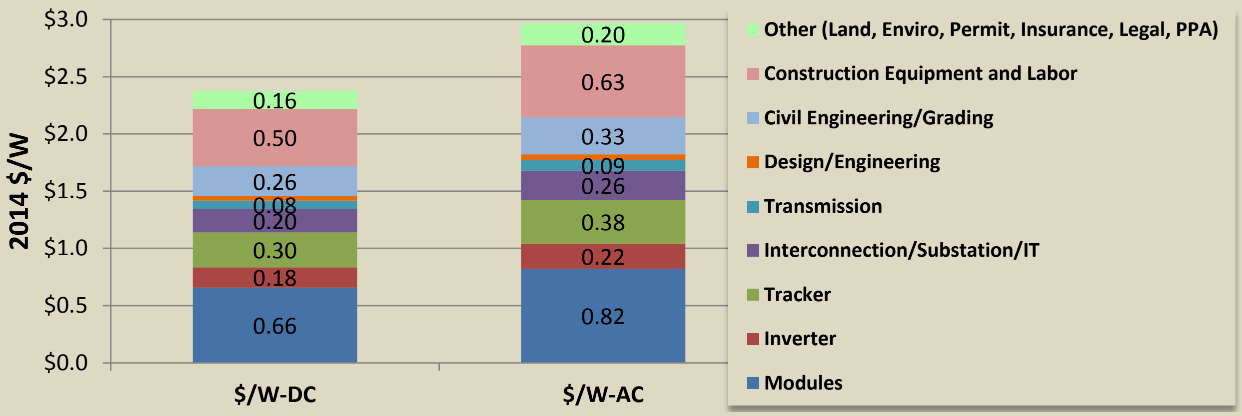
More notable in Figure 8 are the price *penalties* for projects larger than 100 MW_{AC}; two factors may contribute to these apparent *dis*economies of scale for very large projects. As discussed earlier, most of these very large projects have been under construction for several years and may therefore reflect higher module and EPC costs from several years ago. Moreover, these mega-scale projects – some of which involve more than 8 million modules and project sites of nearly 10 square miles – may face greater administrative, regulatory, and interconnection costs than do smaller projects.

[23] These empirical findings more or less align with recent modeling work from NREL (Fu et al. 2015), which also finds only modest scale economies for a 100 MW project compared to a 10 MW project, and no additional scale economies for projects larger than 100 MW.

Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this chapter generally represent empirical *top-down* price estimates gathered from sources (e.g. corporate financial filings, FERC filings, the Treasury's Section 1603 grant database) that typically do not provide more granular insight into component costs. In contrast, several recent publications (Fu et al. 2015; GTM Research and SEIA 2015; Bloomberg New Energy Finance 2015) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed price. Each type of estimate has both strengths and weaknesses – e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check, while bottom-up estimates provide more detail but rely on modeling.

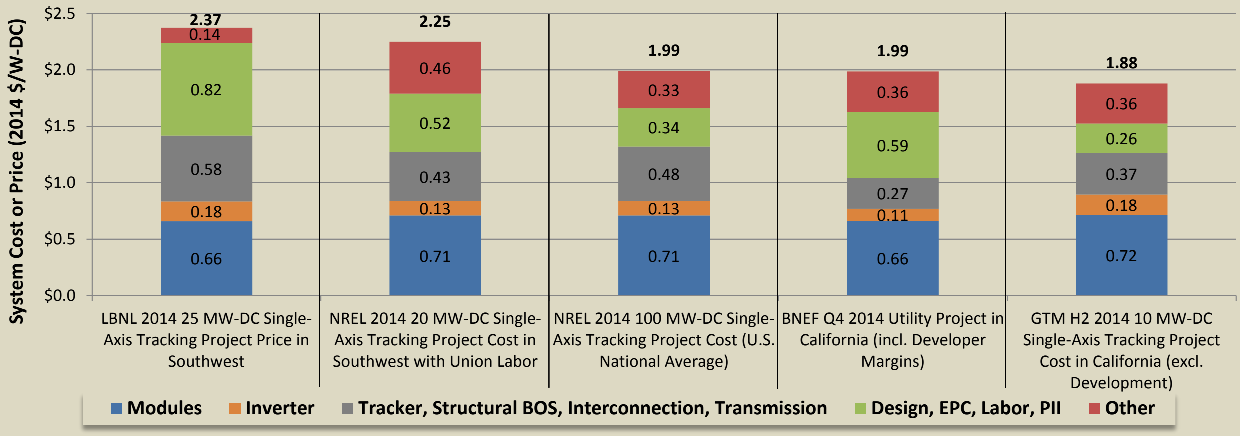
This text box explores to what extent the two different types of price estimates are in alignment, and where any differences lie. To aid in this comparison, LBNL obtained a detailed project cost breakdown for one of the PV projects in its price sample: a 20 MW_{AC} (25 MW_{DC}) single-axis tracking c-Si project that came online in the Southwest in 2014. The reported total installed price of this project – \$2.37/W_{DC} or \$2.97/W_{AC} – is comparable to other similar 2014 projects in the LBNL sample, suggesting that this project's detailed cost breakdown may be representative of other similar projects.



Representative Bottom-up Price of 2014 20 MW_{AC} Single-Axis Tracking System

The original cost breakdown for this project reported costs in 67 different categories that, for ease of presentation, are grouped into 9 larger cost bins in the figure above. As shown, the three major hardware components account for almost half of total costs, with 28% (\$0.66/W_{DC} / \$0.82/W_{AC}) coming from the modules, 13% (\$0.30/W_{DC} / \$0.38/W_{AC}) from the tracking/racking system, and 7.5% (\$0.18/W_{DC} / \$0.22/W_{AC}) from the inverters. Construction equipment and labor accounts for another 21% (\$0.50/W_{DC} / \$0.63/W_{AC}), while 11% (\$0.26/W_{DC} / \$0.33/W_{AC}) is attributable to civil engineering and grading.

The figure on the next page compares the cost breakdown for this seemingly representative project with modeled bottom-up estimates from NREL (Fu et al. 2015), BNEF (Bloomberg New Energy Finance 2015), and Greentech Media (GTM Research and SEIA 2015). Because each of these publications reports costs slightly differently, we had to create fairly broad (and hence rough) cost bins that reflect the "lowest common denominator" in order to compare them. In contrast to the rest of this report, costs in the next graph are shown exclusively in \$/W_{DC} to align with how they are reported in these other publications.



Comparison of Bottom-Up Utility-Scale PV Project Cost Estimates

As shown, the sample LBNL project has the highest installed price – despite reporting among the lowest module costs. That said, the total installed price of $2.37/W_{DC}$ is not too dissimilar from NREL's modeled bottom-up estimate of $2.25/W_{DC}$ for a similar project (i.e., a 20 MW_{DC} tracking c-Si project located in the Southwest and built with union labor). The other three estimates are all lower, with the NREL national and the BNEF model both arriving at about $2/W_{DC}$. The GTM estimate is the lowest as it excludes development costs (captured by the LBNL empirical breakdown); meanwhile, GTM's relatively high inverter costs include the AC subsystem, which other estimates include within interconnection costs. Finally, there are probably other differences in costs captured by the various estimates (e.g., financing costs, developer profit margins, transaction costs) that impede straightforward comparisons.

Among cost categories, the largest discrepancy between the sample LBNL project and the modeled bottom-up prices comes from the category that includes project design, EPC, labor, and permitting, interconnection and inspection ("PII"). One potential explanation for this discrepancy is that the bottom-up models may be modeling current EPC (or other) costs for projects that will be built in the future, whereas the sample LBNL project achieved commercial operation in 2014 and may therefore reflect, for example, EPC costs from some time ago (e.g., from before the project entered the construction phase).

Although it's difficult to pin down the exact reason for the discrepancy in installed prices shown in the figure above, this analysis nevertheless highlights the potentially substantial variation between empirical top-down and modeled bottom-up installed price estimates (and even among the various modeled bottom-up price estimates themselves), as well as the importance of understanding what each price estimate represents.

CSP (6 projects, 1,270 MW_{AC})

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other concentrated solar thermal power (CSP) projects, totaling 1,270 MWAC, that were commercially operational at the end of 2014 and larger than 5 MW_{AC}. Five of these six projects feature parabolic trough technology, while the sixth uses power tower technology (consisting of a total of 3 solar towers). Another large solar tower project that had finished major construction activities in early 2014 but that had not yet entered commercial operation by the end of 2014 has been excluded from the sample.

Figure 9 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2014),[24] and also compares their installed prices to the median installed price of PV (from Figure 6) in each year from 2010 through 2014. The small sample size makes it difficult to discern any trends. In 2014 alone, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($5.10/W vs. $6.16/W). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $6.76/W), while the 2014 power tower project was priced at the higher end of the range of the two trough projects. In general, CSP prices do not seem to have declined over time to any notable extent, in stark contrast to the median PV prices included in the figure.

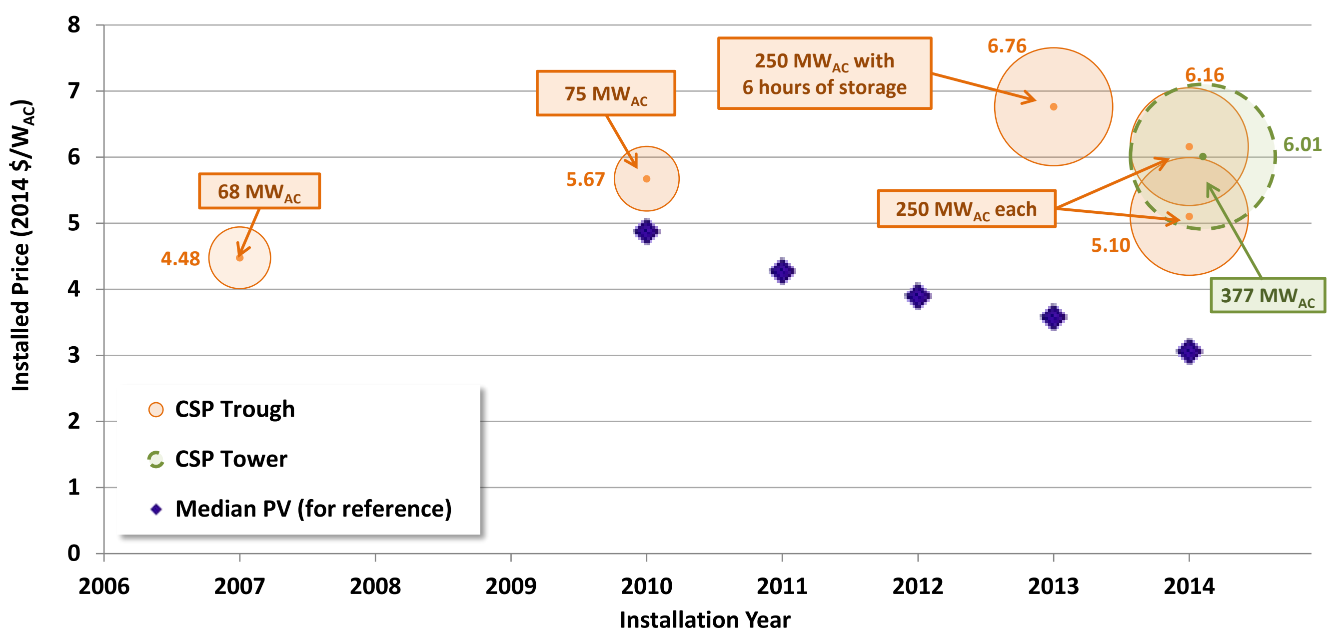


Figure 9. Installed Price of Utility-Scale CSP Projects by Technology and Installation Year

[24] The installed CSP prices shown in Figure 9 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

4. Operation and Maintenance Costs

In addition to up-front installed project costs or prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs incurred to operate and maintain the generating plant itself. In other words, O&M costs – at least as reported here – exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Very few of the utility-scale solar projects that have been operating for more than a year are owned by investor-owned utilities, which FERC requires to report on Form 1 the O&M costs of the power plants that they own.[25] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). It also appears that most investor-owned utilities (with the exception of Florida Power & Light) do not report empirical O&M costs for individual solar projects, but instead report average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 1 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Year	PG&E[26]		PNM		APS[27]		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	

Table 1. Operation and Maintenance Cost Sample

Despite these limitations, Figure 10 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (blue solid line) and $/MWh (red dashed line)[28]. The

[25] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses" – namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).
[26] As PG&E does not report operating costs for its solar projects on FERC Form 1, we turned to O&M costs reported in a CPUC compliance report (Middlekauff and Mathai-Jackson 2015) that unfortunately did not include usable cost data for 2014.
[27] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 168 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 7 utility-scale solar plants with a combined capacity of 158 MW_{AC}.

whiskers represent both the lowest and the highest utility fleet-wide cost in each year. The dotted line refers to FP&L's project-specific annual O&M costs of its 75 MW CSP plant.

Average O&M costs for the PV plants within this sample have steadily declined from about \$30/kW$_{AC}$-year (or \$19/MWh) in 2011 to about \$17/kW$_{AC}$-year (\$8/MWh) in 2014. This decline could potentially indicate that utilities are capturing economies of scale as their PV project fleets grow over time, although the most recent drop from 2013 to 2014 may simply be a result of missing PG&E's costs for 2014 (PG&E's reported costs for 2012 and 2013 were above average). In 2014, all but one PV project had O&M costs of less than \$20/kW$_{AC}$-year (or \$11/MWh), which is lower than recent medium-term projections by bond rating agencies (see the O&M cost section of Bolinger and Weaver (2014)).

The only CSP plant in our sample reports higher O&M costs, in the \$40-\$50/kW$_{AC}$-year range for 2013 and 2014.

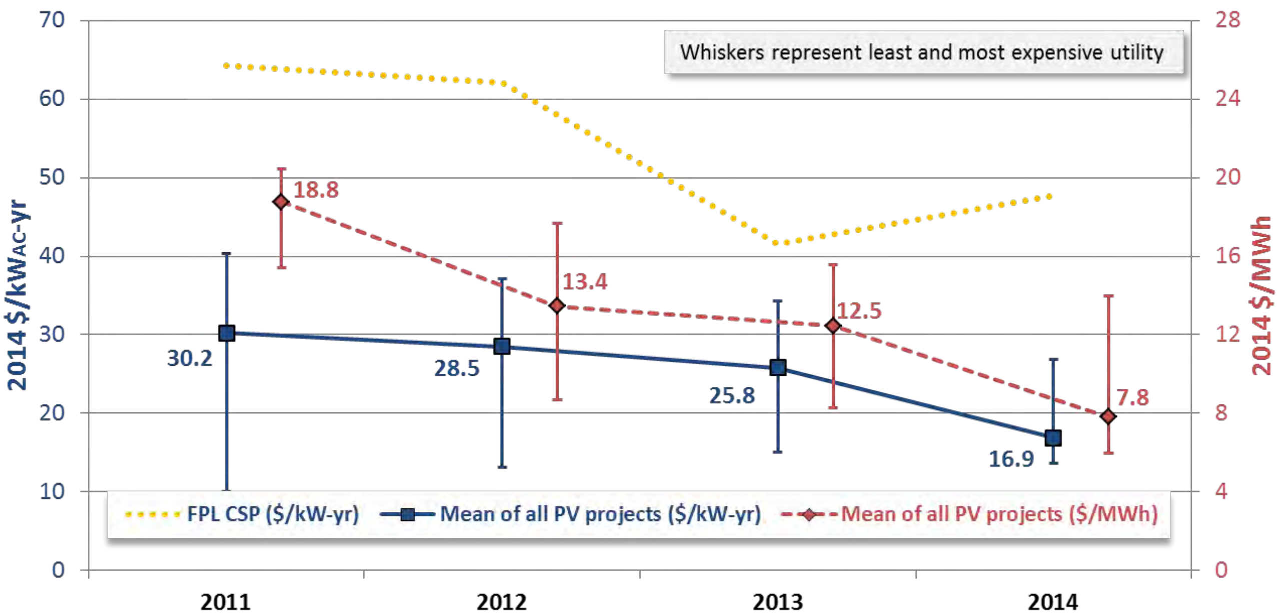


Figure 10. Empirical O&M Costs Over Time

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

[28] 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.

5. Capacity Factors

At the close of 2014, more than 140 utility-scale solar projects (again, ground-mounted projects larger than 5 MW_{AC}) had been operating for at least one full year (and in some cases for many years), thereby enabling the calculation of capacity factors.[29] Sourcing net generation data from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and state regulatory filings, this chapter presents net capacity factor data for 128 PV projects totaling 3,201 MW_{AC}, two CPV projects totaling 35 MW_{AC}, and thirteen CSP projects (a mix of parabolic trough and power tower projects, with and without thermal storage) totaling 1,390 MW_{AC} (and for which only the solar generation is reported here – no gas or oil augmentation is included). The PV sample size of 128 projects totaling 3.2 GW is double the amount analyzed in last year's edition of this report, and should once again increase significantly in next year's edition (along with more CSP as well), as the record amount of new utility-scale solar capacity that came online in 2014 will have its first full operating year in 2015.

PV (128 projects, 3,201 MW_{AC})

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

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

[29] 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.

Figure 11 illustrates and supports this hypothesis, by breaking out the average net capacity factor ("NCF") by project vintage across the sample of projects built from 2010 through 2013 (and by noting the relevant average project parameters within each vintage). The capacity factors presented in Figure 11 represent *cumulative* capacity factors – i.e., calculated over as many years of data as are available for each individual project (a maximum of four years, from 2011 to 2014, in this case), rather than for just a single year (though for projects completed in 2013, only a single year of data exists at present) – and are expressed in *net*, rather than *gross*, terms (i.e., they represent the output of the project net of its own use). Notably, they are also calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[30] yielding higher capacity factors than if reported in DC terms,[31] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or conventional energy), which are also calculated in AC terms.

As shown, the average capacity factor increases only slightly from 2010- to 2011-vintage projects, due primarily to a higher proportion (in capacity terms) of projects using tracking among 2011-vintage projects, given virtually no change in the average ILR or GHI across these two vintages. Projects built in 2012 and especially 2013, however, have progressively higher capacity factors on average, driven by an increase in both average ILR and GHI in each year.

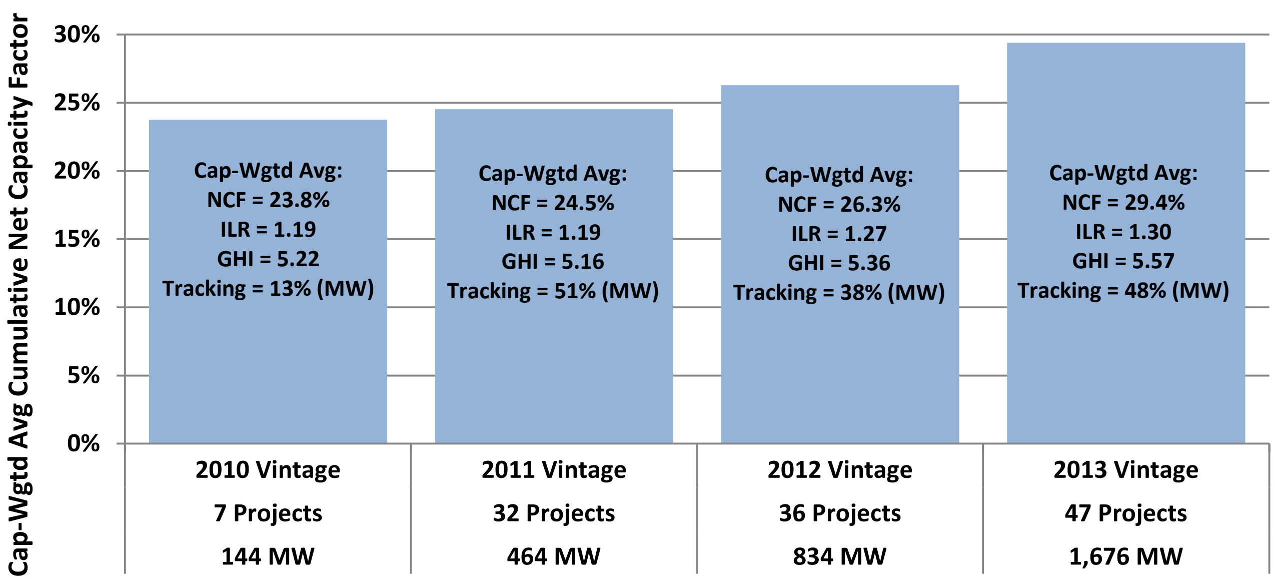


Figure 11. Cumulative PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

Because Figure 11 analyzes *cumulative* capacity factors, one other possible explanation for the upward trend by vintage could be if the solar resource across the United States were significantly stronger in 2014 than in 2011-2013. If this were the case – which seems unlikely based on ex-post annual solar resource data (3Tier 2013; Vaisala 2014; Vaisala 2015) – then 2013-vintage projects might be expected to exhibit higher cumulative capacity factors than 2010-2012

[30] 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].
[31] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

projects, given that 2014 is the only applicable performance year for a 2013-vintage project. To check against this possibility, Figure 12 replicates Figure 11, but based on single-year 2014 capacity factors rather than cumulative capacity factors. In other words, each vintage is measured based on its performance during the same single year – 2014 – rather than over a one- to four-year period, depending on vintage. As shown, the upward trend still holds, suggesting that ILR, GHI, and tracking are the true drivers.[32]

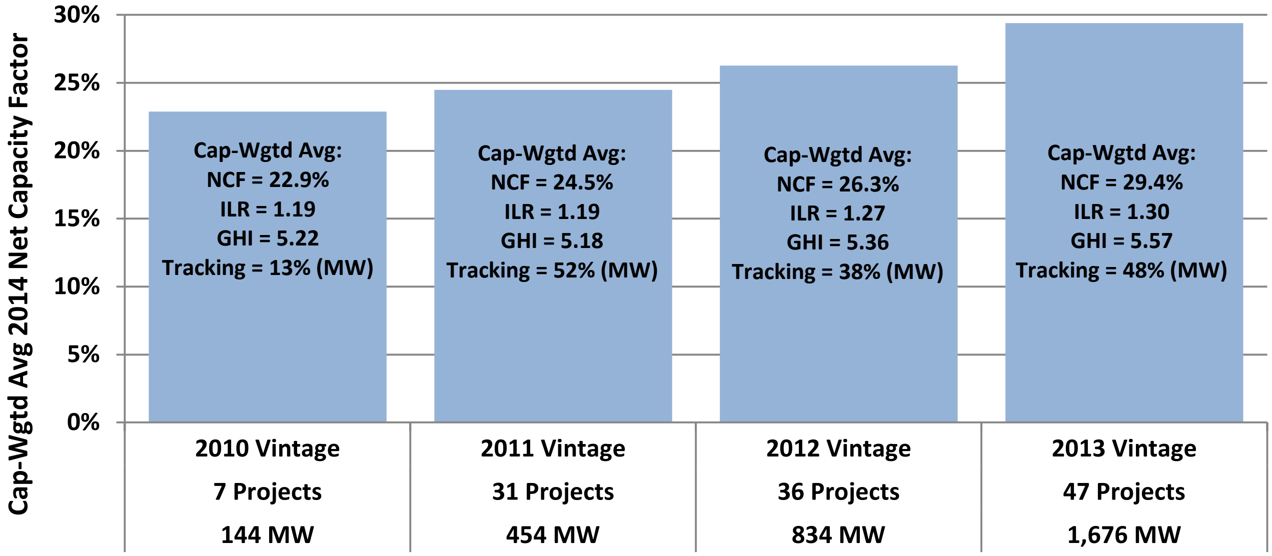


Figure 12. 2014 PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

To the extent that this observable time trend in net capacity factor by project vintage is, in fact, attributable to a time trend in one or more of the other variables noted, it is perhaps best to measure the effect of those other variables directly. Figure 13 does just that, by categorizing the entire data sample in four different ways: by solar resource strength (in GHI terms), by fixed-tilt versus tracking systems, by the inverter loading ratio, and by module type (c-Si versus thin-film). The capacity-weighted average net capacity factor across the entire sample is 27.5%, the median is 26.5%, and the simple average is 25.6%, but there is a wide range of individual project-level capacity factors (from 14.8% to 34.9%) around these central numbers.

[32] There is one less project in the sample for Figure 12 than for Figure 11, due to 2014 net generation data not yet being available for one project in New Jersey.

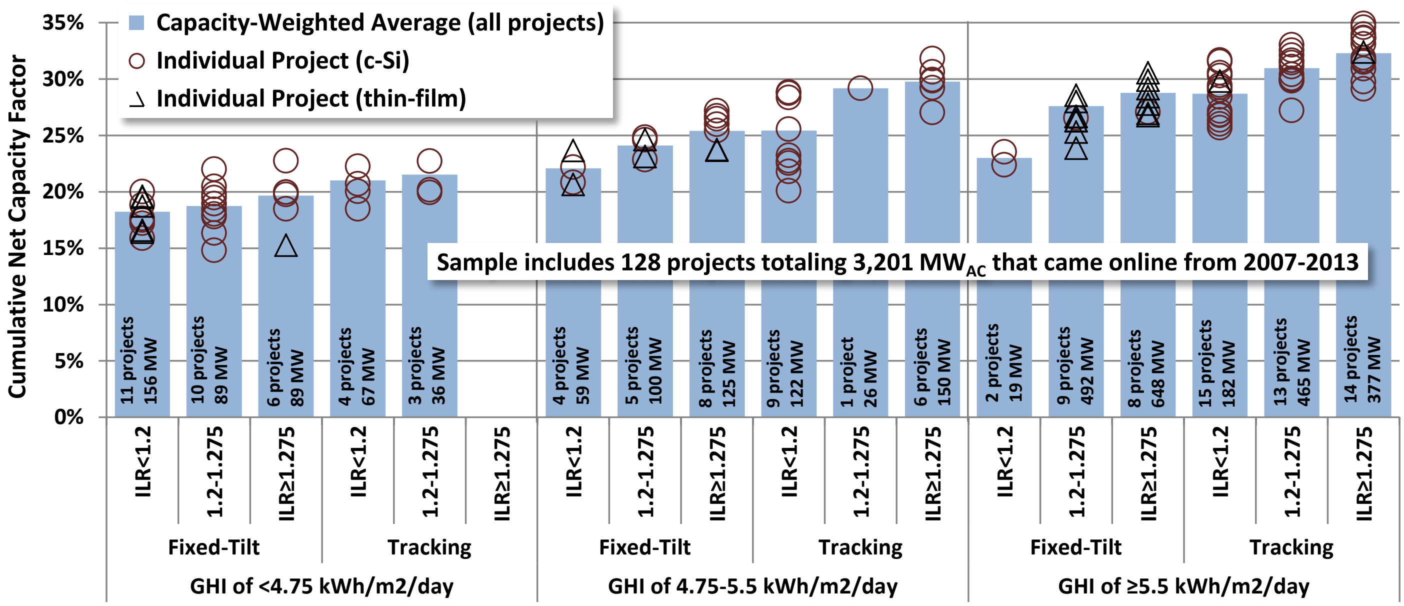


Figure 13. Cumulative PV Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, Inverter Loading Ratio, and Module Type

Each of the four variables explored in Figure 13 is discussed in turn below.

- **Solar Resource:** Each project in the sample is associated with a global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Solar resource bin thresholds (<4.75, 4.75-5.5, and ≥5.5 kWh/m^2/day GHI) were chosen to ensure that a sufficient number of projects fall within each bin.[33] Not surprisingly, projects sited in stronger solar resource areas have higher capacity factors, all else equal. The difference can be substantial: the capacity-weighted average net capacity factors in the highest resource bin, for example, average 8% higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending 5-9% depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** Tracking (all single-axis in this sample) boosts average capacity factor by 3-4% on average (in absolute terms), depending on the resource bin (4% on average across all three resource bins).

- **Inverter Loading Ratio (ILR):** Figure 13 breaks the sample down further into three different inverter loading ratio bins: <1.2, 1.2-1.275, and ≥1.275.[34] The effect on average capacity factor is noticeable: across all resource bins and fixed/tracking bins, the absolute difference in capacity factor between the highest and lowest inverter loading ratio bin ranges from 1% to 6% (for an average of 4%).

[33] Thirty-four projects totaling 436 MW fall into the lowest resource category of less than 4.75 kWh/m^2/day, 33 projects totaling 582 MW fall into the middle resource category of between 4.75 and 5.5 kWh/m^2/day, and 61 projects totaling 2,183 MW fall into the highest resource category of at least 5.5 kWh/m^2/day.
[34] These ILR bins were chosen to ensure a roughly equal number of projects in each bin. The lowest ILR bins include 45 projects totaling 605 MW$_{AC}$, the middle bins include 44 projects totaling 1,208 MW$_{AC}$, and the highest bins include 42 projects totaling 1,388 MW$_{AC}$.

- **Module Type:** Figure 13 differentiates between projects using c-Si and thin-film modules by the shape and color of the markers denoting individual projects (the capacity-weighted averages include *both* c-Si and thin-film projects). Though somewhat difficult to tease out, the differences in project-level capacity factors by module type are generally small (smaller than for the other variables discussed above), and do not appear to exhibit any sort of pattern. That said, the prevalence of fixed-tilt thin-film projects within the highest resource bin is noticeable. As mentioned in an earlier section of this report, however, many of the new thin-film projects completed in 2014 (which will enter our capacity factor sample in next year's report) have deployed single-axis trackers.

CPV (2 projects, 35 MW_{AC})

The two CPV-only projects in the sample (the 5 MW_{AC} Hatch and the 30 MW_{AC} Cogentrix Alamosa projects) use virtually the same high-concentration technology (from Amonix), and both appear to be underperforming – both relative to publicly stated expectations and to how a single-axis tracking PV project would probably have performed in similar conditions. In November 2011, a few months after Hatch came online and a few months before Alamosa went online, a conference presentation from Amonix suggested a 31.5% capacity factor for Hatch and a 32.5% capacity factor for Alamosa (Pihowich 2011).[35] This 31.5-32.5% range is consistent with the empirical PV capacity factors seen in the second column from the right in Figure 13, which – except for the fact that they feature dual-axis, rather than single-axis, tracking – is where these two CPV projects would otherwise fall based on resource strength and inverter loading ratio. Actual experience to date, however, has been below this range: Hatch's 20.9% capacity factor in 2012 dropped to 18.5% in 2013 and 18.1% in 2014, while Cogentrix Alamosa posted a 24.9% capacity factor in 2013, followed by 24.2% in 2014.[36] The 2013 and 2014 capacity factors may have been reduced somewhat by the reportedly below-average insolation levels in the southwestern United States during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015).[37]

[35] The Amonix slide deck (Pihowich 2011) contains conflicting information: it lists expected generation numbers that equate to a 31.5% capacity factor for Hatch, yet also states a slightly lower capacity factor estimate of 29.4% – either of which is higher than actual experience. Meanwhile, documents from El Paso Electric (the offtaker) list 9,189 MWh, or a 20.8% capacity factor, as the expected output of Hatch (the project met this expectation in 2012, but fell short in 2013 and 2014). For Cogentrix Alamosa, an April 2011 environmental assessment prepared for the DOE's Loan Program Office assumed a 29% capacity factor, although the current Loan Program Office project description notes annual generation of 58,000 MWh, equivalent to just 21.9% (well below the >24% achieved to date). The reason for these disparate expectations (for both projects) is not clear, though one potential explanation might have to do with timing – i.e., the current El Paso Electric and Loan Program Office numbers might be more recent, therefore potentially reflecting some degree of actual experience.

[36] A third project that includes a mix of PV and CPV technologies – the 6.9 MW_{AC} SunE Alamosa project – has performed better than the two CPV-only projects, having logged a 28.7% cumulative capacity factor over six full years of operation (from 2008-2013). The CPV portion of the project, however, only accounts for about 12% of the project's total capacity (the rest being PV with diurnal (~80%) or seasonal (~7%) tracking), and unfortunately, the project-level net generation data are not granular enough to enable a determination of how the CPV and PV portions of this project have performed independently.

[37] The entire year 2014 was an average to slightly above average solar year in the West, and an average to slightly below average solar year elsewhere in the continental United States. These annual averages mask important seasonal divergences, however – e.g., the above-average insolation tended to be concentrated in the less-important

CSP (13 projects, 1,390 MW_{AC})

Three new CSP projects totaling 892 MW_{AC} achieved commercial operation in late 2013, providing a significant boost to this year's CSP capacity factor sample. Solana is a 250 MW_{AC} (net) parabolic trough project with six hours of molten salt storage located in Arizona; Genesis is a 250 MW_{AC} (net) parabolic trough project without storage located in California; and Ivanpah is a 377 MW_{AC} (net) power tower project without storage located in California.

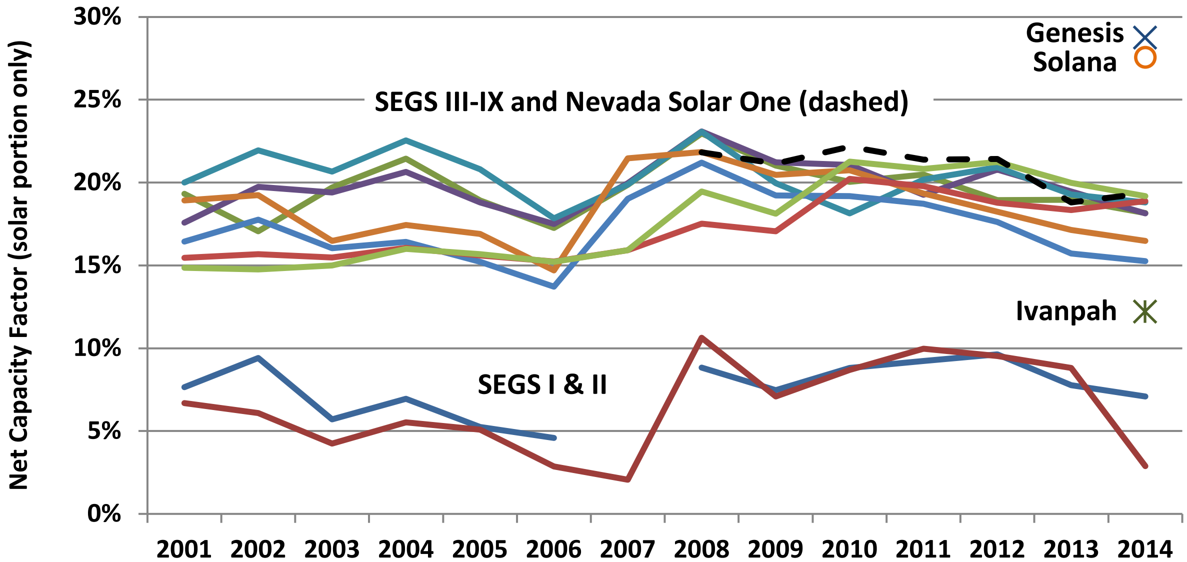


Figure 14. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

Figure 14 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 14 [38]) of our CSP project sample. The two new trough projects performed at roughly 28-29% capacity factors in 2014, while the Ivanpah power tower project performed at ~12% capacity factor. For at least Solana (with 6 hours of storage) and Ivanpah, these first-year numbers are below long-term expectations of 41% and 27%, respectively, and are projected to improve in future years as these projects overcome typical start-up challenges and are fine-tuned for optimal performance (Danko 2015; Stern 2015).[39] Indeed, the performance of these two projects has already improved somewhat in the

non-summer months, while the critical months of May through September were generally below average across much of the United States, including the Southwest (Vaisala 2014; Vaisala 2015).

[38] Many 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 19.4% solar-only to 19.8% gas-included in 2014), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 60-200 basis points in 2014, depending on the project. The Ivanpah power tower project also burns gas – and reportedly more than originally anticipated (Danko 2015) – though data on its gas-fired generation in 2014 were not available at the time of writing.

[39] Ivanpah documentation suggests that this initial ramp-up could last as long as four years (Danko 2015).

first half of 2015.[40] Even despite these teething issues, however, the two new trough projects performed significantly better in 2014 than the existing fleet of ten older trough projects in the sample, including the nine SEGS plants (totaling 392 MW_{AC}) that have been operating in California for more than twenty years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[41]

These ten older trough projects tend to fall into two groupings, with SEGS I and II set apart from the rest by significantly lower capacity factors, perhaps attributable to some combination of separate ownership from SEGS III-IX as well as different plant characteristics (such as the size of the collector field relative to the capacity and efficiency of the steam turbine). Nearly all of these projects experienced lower solar-only capacity factors in 2013 and 2014 than in other recent years. This decline is potentially attributable in part to inter-year variations in the solar resource, which was below average in the southwestern United States (where these projects are located) during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015), with summer being particularly important for CSP projects.

Looking ahead, another 250 MW_{AC} (net) parabolic trough project in California without storage (Mojave) achieved commercial operation in late 2014, and so will enter our capacity factor sample in 2015. A second power tower project – the 110 MW Crescent Dunes project in Nevada, with 10 hours of storage – is expected to be placed in service later in 2015 after a prolonged commissioning process. Along with the three new projects added to the sample this year (which should continue to mature over the next few years), these two new additions will expand the CSP performance data set in future years.

[40] For example, Ivanpah generated 309,913 MWh in the first six months of 2015 (for an annualized capacity factor of 18.2%), compared to 173,138 MWh in the first six months of 2014 (an annualized capacity factor of 10.2%). For Solana, the corresponding numbers are 352,569 MWh (32.5%) vs. 314,906 MWh (29.0%).

[41] One additional parabolic trough project – the 75 MW_{AC} Martin project in Florida – is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

6. Power Purchase Agreement ("PPA") Prices

The cost of installing, operating, and maintaining a utility-scale solar project, along with its capacity factor – i.e., all of the factors that have been explored so far in this report – are key determinants of the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale solar projects in the U.S. The sample includes a total of 109 contracts totaling 8,578 MW_{AC} and broken out as follows: 100 PV PPAs totaling 7,234 MW_{AC}, two CPV PPAs totaling 35 MW_{AC}, one 7 MW_{AC} PPA that is a mix of PV and CPV, and 6 CSP PPAs (four parabolic trough, two power tower) totaling 1,301 MW_{AC}.

The population from which this sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, 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 does not reflect the project's total revenue requirements (at least on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons – i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[42] 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) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[43] As a practical matter, this means that we exclude "avoided cost" contracts – discussed in the text box on the next page – from our PPA price sample as well.

[42] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[43] 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 encourage specifically 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 affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases – presumably to the upside.

Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets

As discussed in the text, virtually all of the PPAs analyzed in this chapter result from competitive solicitations or some other form of bilateral negotiation. Yet as the cost of solar has fallen to more-competitive levels, a "new" market for utility-scale solar (which is actually one of the *oldest* markets for renewables in the United States, in existence ever since the Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978) has emerged over the past year or so. Specifically, PURPA requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects) at prices that represent their "avoided cost" – i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. As a matter of policy, we exclude these "avoided cost" contracts from our PPA price sample, because they are FiT-like and, in some states, also involve unbundling RECs; yet, as discussed below, this growing market is not to be ignored.

Solar developers have been capitalizing on these avoided cost contracts for several years now in North Carolina, though the 5 MW capacity limit in that state means that most of the more than 150 projects that are operational in North Carolina fall below our threshold of what is considered to be "utility-scale." But in the past year, numerous avoided cost contracts for larger projects have been announced in other states that had not previously seen any solar development to speak of. For example:

- In Utah, at least two new 80 MW_{AC} PV projects (in addition to a number of smaller projects) should begin commercial operation by the end of 2015, selling electricity to PacifiCorp through 20-year avoided cost contracts. More than 700 MW of additional solar capacity is under development in Utah and could come online in 2016 under these same avoided cost contracts. Although the prices for these larger contracts are subject to negotiation, they are based loosely on PacifiCorp's published avoided cost rates, which are in the neighborhood of $50-$60/MWh when averaged over the 20-year contract term.

- Just to the north in Idaho, Idaho Power announced in late 2014 that it had recently entered into avoided cost contracts for 461 MW of utility-scale PV, and that another 885 MW was actively seeking such contracts. Idaho Power's avoided cost contracts feature pricing that varies by time of day and season, but averages out to about $60-70/MWh over the 20-year term.

This recent onslaught of applications for avoided cost contracts has prompted the utilities involved and their state utility regulators to re-evaluate these contracts and the utilities' PURPA requirements. In early 2015, for example, Idaho Power requested that its standard avoided cost contract term be reduced from 20 to just 2 years; regulators subsequently reduced the term to 5 years while they examined the issue, and in August 2015 agreed to impose a 2-year term. Around the same time, regulators in North Carolina rejected a similar utility request to lower the capacity threshold, shorten the contract term, and reduce contract pricing for solar projects. Meanwhile in Utah, PacifiCorp is also pushing back (as developers with Idaho projects that were stranded by the reduction in contract term are now looking south to PacifiCorp as a more-viable market), and would like to reduce solar compensation via a reduction in the capacity credit assigned to solar within the avoided cost calculation. How these various proceedings play out could significantly affect the future of utility-scale solar within these states. In the near term, however, grandfathered contracts will fuel a frenzy of new PV project construction in these emerging states through 2016.

For each of the contracts in the sample,[44] we have collected the contractually locked-in PPA price data over the full term of the PPA,[45] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[46] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum

[44] 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 two or more PPAs may be tied to a single project.
[45] The minimum PPA term in the sample is 10 years (though the two 10-year contracts in the sample are effectively 4-year "bridge" PPAs with a California municipality, whereby the buyer takes 100% of the output for the first four years and then, once a long-term contract with an investor-owned utility begins in 2019, just 1% of the output in the last six years). The maximum is 34 years, the mean is 22.8 years, the median is 25 years, and the capacity-weighted average is 23.4 years.
[46] 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 2015* 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.

amount of revenue required by[47]) these projects over the life of the contract – at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation) [48] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[49,50] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized levelized cost of energy ("LCOE").

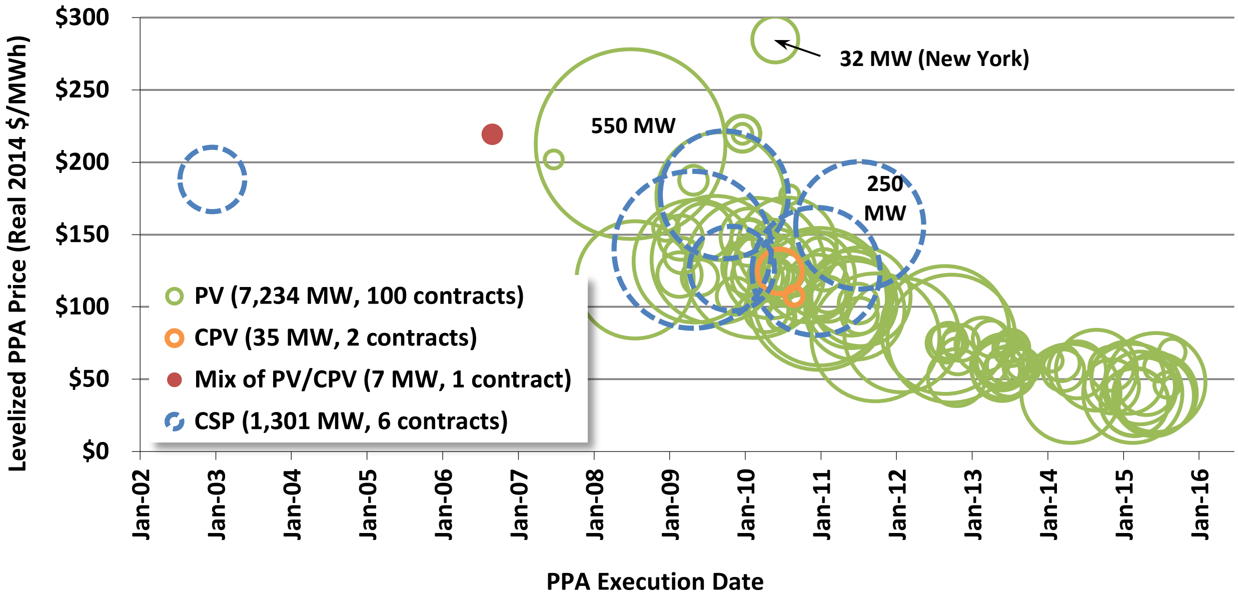


Figure 15. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

[47] 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.

[48] In addition to the other federal incentives listed, eleven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee didn't affect the PPA price.

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

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

Figure 15 shows trends in the levelized (using a 7% real discount rate) PPA prices from the entire sample over time. Each bubble in Figure 15 represents a single PPA, with the area of the bubble corresponding to the size of the contract in MW and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[51] Different solar technologies (e.g., PV versus CPV versus CSP) are denoted by different colors and patterns.

Figure 15 provides a number of insights:

- PPA pricing has, in general, declined over time, to the point where recent PPAs have been priced as aggressively as $40/MWh levelized (in real, 2014 dollars), or even lower. In the Southwest (where these low-priced projects are primarily located), pricing this low is, in some cases, competitive with in-region wind power.[52] This is particularly the case when considering solar's on-peak generation profile, which can provide ~$25/MWh of TOD value relative to wind.[53]

- Although at first glance there does not seem to be a significant difference in the PPA prices required by different solar technologies, it is notable that all of the recent PPAs in the sample employ PV technology. Back in 2002 when the Nevada Solar One (CSP) PPA was executed, PV was too expensive to compete at the wholesale level, but by 2009-2011 when the other five CSP PPAs in the sample were executed, PV pricing had closed the gap. Since then, virtually all new contracts have employed PV technology, while a number of previously-executed CSP contracts have been either 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.[54]

- Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects. Very large projects often face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.

[51] Because PPA prices reflect market expectations at the time a PPA is executed – which could be two years or more in advance of when the project achieves commercial operation – the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices.
[52] See, for example, the text box in Bolinger and Weaver (2013) that compares the economics of the co-located Macho Springs wind and solar projects.
[53] For further explanation, see the text box titled *Estimating PV's TOD Value* in the 2013 edition of this report (Bolinger and Weaver 2014). Also note that the levelized PPA prices shown in Figure 15 (and throughout this chapter) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, PV's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the buyer.
[54] That said, SunPower has been quietly rolling out its new low-concentration (7 suns) C7 CPV technology, with a 1 MW_{AC} pilot project at Arizona State University (online in early 2013); a contract with Apple for the 20 MW_{AC} Fort Churchill Solar Project (scheduled to come online in 2015) to power its data center near Reno, NV; and a sale of technology to a project in China. At present, no cost or price information is available for these projects.

- Not surprisingly, the highest-priced contract in the sample comes from Long Island, which does not enjoy the abundant sunshine of the Southwest (where most of our sample is located – 93% of the total capacity within the PPA sample is located in CA, NV, AZ, or NM), and where wholesale power prices are high due to transmission constraints.

Not all of the projects behind the contracts shown in Figure 15 are fully (or even partially) operational, though all of them are still in play (i.e., the sample does not include PPAs that have been terminated). Figure 16 shows the same data as Figure 15, but broken out according to whether or not a project has begun to deliver power.[55] Understandably, most of the more-recently signed PPAs in the sample pertain to projects that are still in development or under construction, and have not yet begun to deliver electricity under the terms of the PPA. Given that many of these same PPAs are also the lowest-priced contracts in the sample, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown here.[56] That said, a recent and related modeling analysis (Bolinger, Weaver, and Zuboy 2015) finds that today's aggressive PPA prices can indeed pencil out using modeling assumptions that are based on best-in-class PV data presented in other sections of this report. Moreover, as described in the text box on the next page, a survey of recent solicitation responses reveals a deep field of projects bidding into solicitations at these low prices – i.e., the recent low prices shown in Figure 15 and Figure 16 do not appear to be one-off anomalies.

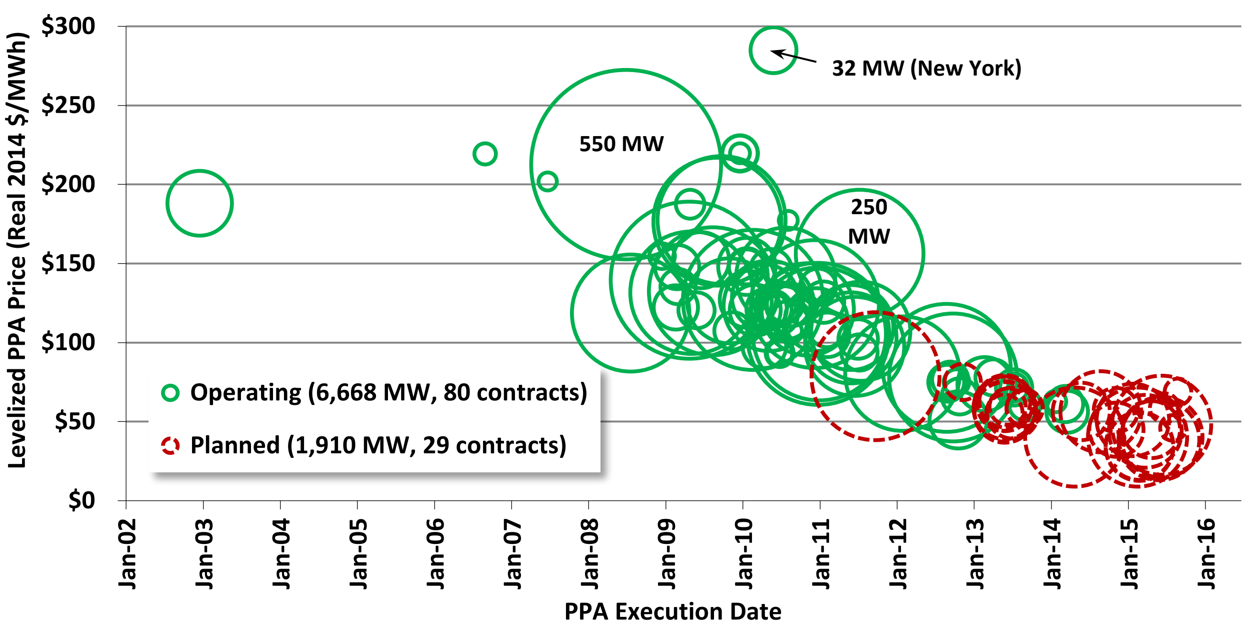


Figure 16. Levelized PPA Prices by Operational Status and PPA Execution Date

[55] If a project had begun to deliver power by August 2015 – even if not yet fully operational or built out to its contractual size – it is characterized as "operating" in Figure 16. Only those projects that were still in development or were under construction but not yet delivering power are characterized as "planned."

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

Solicitation Responses Reveal Deep Market at Low Prices

Although our sample of low-priced solar PPAs signed in 2014 and so far in 2015 is relatively small (21 contracts totaling 1.33 GW), a survey of developer responses to several recent utility solicitations suggests that there is considerable depth in the market at these low price levels, at least in the Southwest. For example:

- Southwestern Public Service's 2014 request for proposals ("RFP") for 200 MW of solar received 53 transmission-level project bids totaling 4,040 MW and 59 distribution-level project bids totaling 1,210 MW (for a total of 5,250 MW – more than 26 times the 200 MW target). Of the transmission-level proposals, 2,718 MW bid levelized prices ranging from $40-$50/MWh, while another 1,182 were priced between $50-$60/MWh. Of the distribution-level proposals (typically featuring smaller projects), 240 MW bid levelized prices ranging from $40-$50/MWh while 600 MW were priced from $50-60/MWh. Many of these projects are located in New Mexico, which provides a 10-year state production tax credit that helps developers to lower PPA prices (though not all bidders assumed full receipt of the state PTC).
- In late 2014 and early 2015, NV Energy issued two 100 MW renewable energy RFPs; bidders in the 2014 RFP were allowed to re-bid into the 2015 RFP, and two 100 MW PV projects were ultimately selected. One of the winning projects is priced at $46/MWh flat over 20 years (i.e., $38.6/MWh levelized in real 2014 dollars), while the other starts at $38.70/MWh (nominal) and escalates at 3%/year over 20 years (i.e., $40.1/MWh levelized in real 2014 dollars). Of the 2,537 MW of renewable resources that bid (or re-bid) into the 2015 RFP, more than 90% were solar, while wind and geothermal accounted for just 8% and 2%, respectively. Though no pricing information is available for the non-winning bids, several hundred additional MW of shortlisted capacity were reportedly bid at prices very similar to the winning bids. Moreover, NV Energy noted that the solar bids were priced lower than the wind or geothermal bids, and also better matched its load profile.
- Austin Energy's 2015 RFP for 600 MW of solar received 149 unique proposals totaling 7,976 MW (more than 13 times coverage) from 33 different bidders. Almost 1,300 MW were reportedly bid at levelized prices of $45/MWh or less.

Taken as a whole, these responses suggest that there is a significant amount of utility-scale PV capacity capable (at least with the 30% ITC) of selling electricity at very low prices in the Southwest. Moreover, at these low price levels, solar can compete head on with wind power in terms of both price and generation profile (for more on comparisons of solar and wind in the Southwest, see the text box titled "Estimating PV's TOD Value" in the 2013 edition of this report, or the text box on the co-located Macho Springs wind and solar projects in the 2012 edition).

More than two-thirds of the PV 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 17 illustrates this decline by plotting over time, in real 2014 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts).

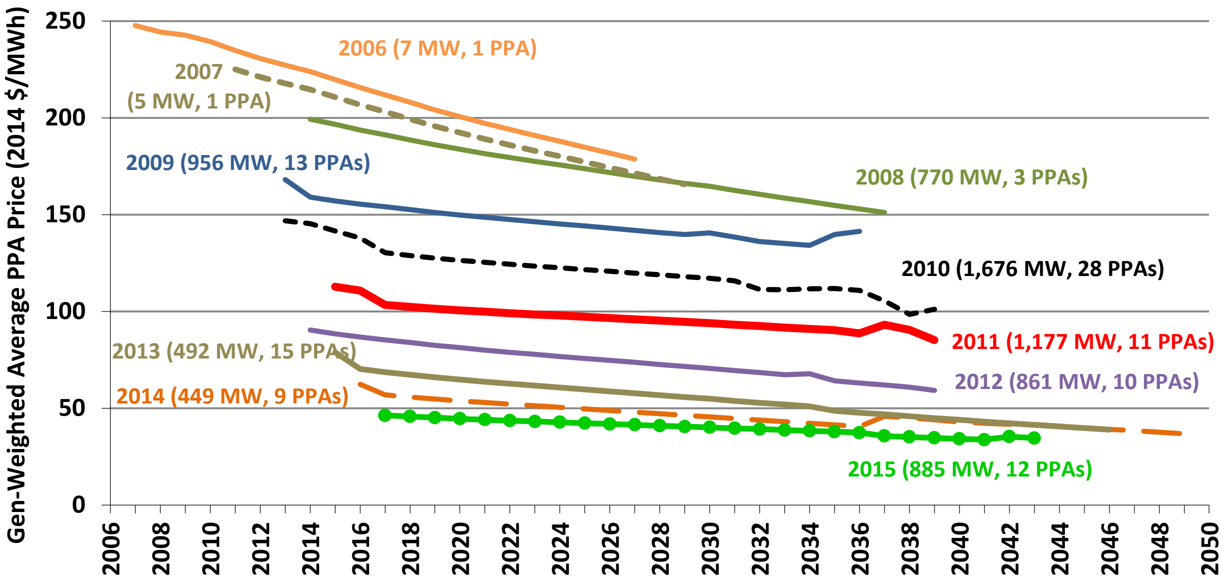


Figure 17. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013). Figure 18 illustrates this potential value by plotting the future stream of average PV PPA prices from contracts executed in 2014 and 2015 (i.e., the same two lines as the 2014 and 2015 vintage PPA lines in Figure 17 above) against a range of projections of *just the fuel costs* of natural gas-fired generation.[57] Focusing on the 2015 PPA vintage in particular, average PPA prices from PV contracts executed in 2015 start out higher than the range of fuel cost projections in 2017, but decline (in real 2014 $/MWh terms) over time and eventually fall below the reference case gas price projection by 2021 (and below the *entire range* of gas price projections by 2037). On a levelized basis from 2017 through 2040, the 2015-vintage PV PPA prices come to $42.1/MWh (real 2014 dollars) compared to $48.1/MWh for the reference case fuel price projection, suggesting that PV may be able to compete with even just the fuel costs of *existing* gas-fired generators (i.e., not even accounting for the recovery of fixed capital costs incurred by *new* gas-fired generators).

Moreover, it is important to recognize that the PV PPA prices have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain – actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

[57] The national average fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2015* publication, and increase from around $4.67/MMBtu in 2015 to $8.83/MMBtu (both in 2014 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high oil and gas resource case on the low end, and the greater of the high oil price or high economic growth cases on the high end (since AEO 2015 does not include a low oil and gas resource case), and ranges from $4.98/MMBtu to $10.75/MMBtu (again, all in 2014 dollars) in 2040. These fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (these start at roughly 8,100 Btu/kWh and gradually decline to around 7,200 Btu/kWh by 2040).

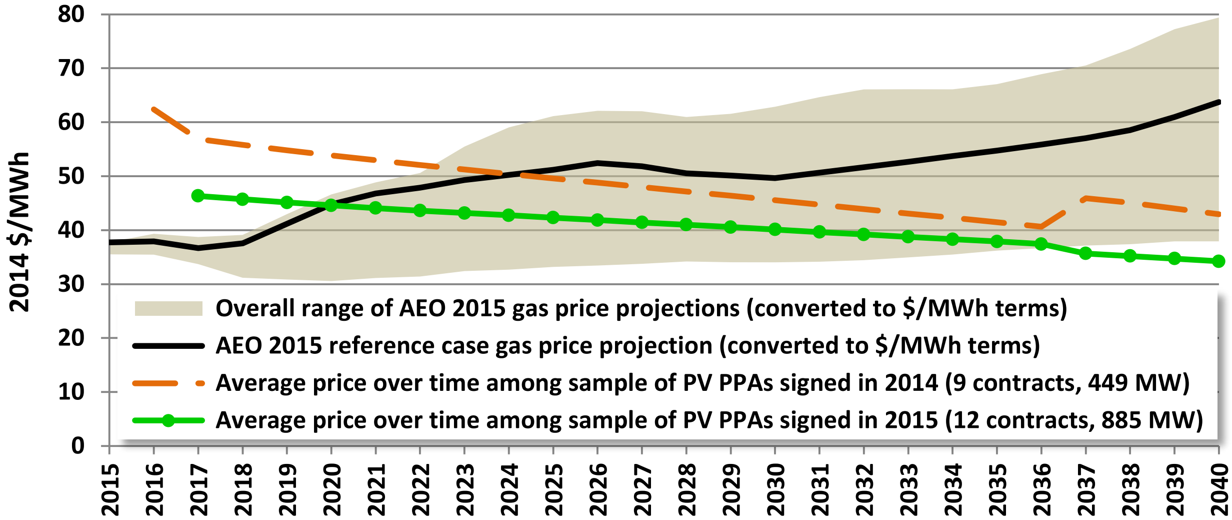


Figure 18. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

In addition to the declining real prices over time within each PPA vintage shown in Figure 17 and Figure 18, the steady march downward across vintages is also evident in Figure 17, demonstrating substantial reductions in pricing by PPA execution date.[58] To provide a clearer look at the time trend, the blue-shaded columns in Figure 19 simply levelize the price streams shown in Figure 17. Based on this sample, levelized real PPA prices for utility-scale PV projects consistently fell by almost $25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. With levelized real PPA prices now below $50/MWh on average (based on the combined 2014/2015 sample), future price declines are likely to be much smaller than in the past.

Figure 19 also shows that the overall spread in pricing has narrowed over time – e.g., the 2013-2015 samples show a tighter range of levelized prices than do the 2009-2011 samples – suggestive of an increasingly mature and transparent market. Moreover, this narrowing has occurred despite the fact that the geographic scope of the market (and sample) has broadened with time. Although the PPAs in our sample are still heavily concentrated in the Southwest, the market is beginning to expand to new parts of the country – notably the Southeast (see the text

[58] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength (though again, 93% of the capacity in the PPA price sample is in the high-insolation states of CA, NV, AZ, and NM), tracking versus fixed-tilt, and c-Si versus thin-film. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PV contracts in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Chapter 3) that are recouped over time through greater energy yield (see Chapter 5), thereby potentially leaving the net effect on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico estimated (based on a review of 216 solar responses to its 2012 Renewable RFP) that the average PPA price benefit of single-axis tracking was just $3/MWh, or less than 4% of a levelized PPA price in the mid-$70/MWh range (O'Connell 2013).

box below) but also states like Utah and Idaho where utilities have had attractive avoided cost rates (see earlier text box on "avoided cost" markets). For example, the 2015 PPA price sample includes contracts not only in the usual Southwestern states, but also in Florida, Arkansas, and Alabama – and at prices not too far above those seen in the Southwest.

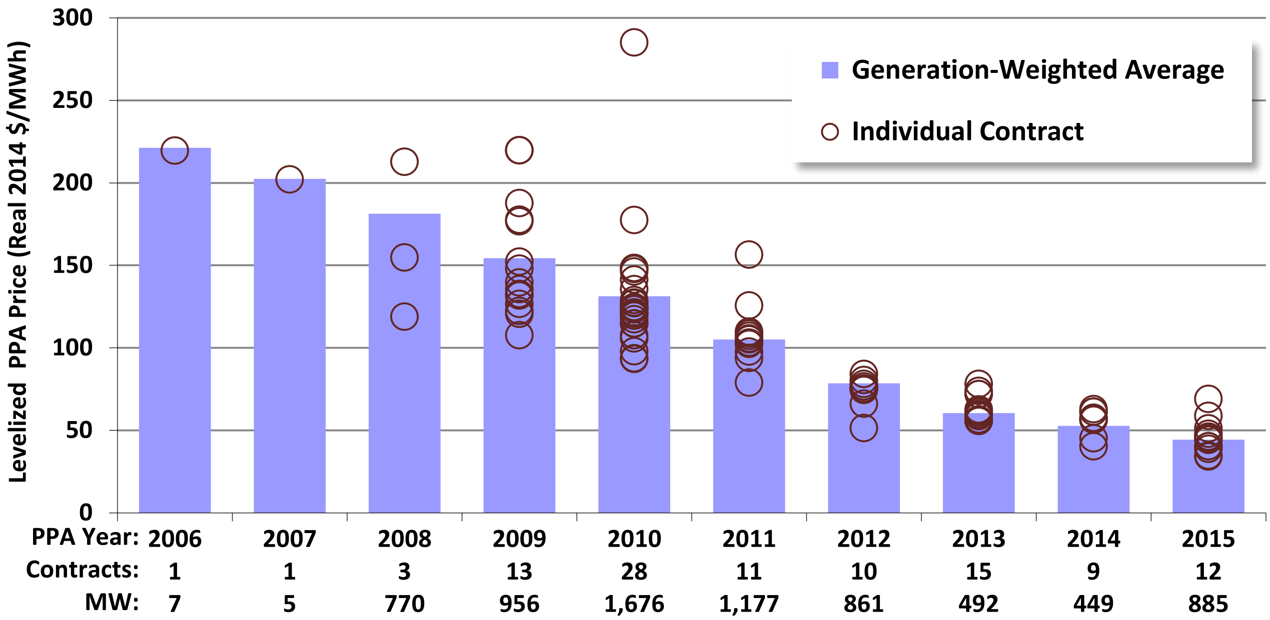


Figure 19. Levelized PV PPA Prices by Contract Vintage

Trend to Watch: The Rise of the South

Although the sample of PPA prices analyzed in this chapter is highly concentrated in the southwestern United States – i.e., 97% of the 8.7 GW of capacity in the sample is located in CA (68%), NV (11%), AZ (11%), TX (4%), NM (3%), and CO (1%) – there have been a number of notable announcements over the past year about new utility-scale solar PPAs being signed at competitive prices in several *southeastern* states that have not previously seen much development. The following non-exhaustive list of new contracts (only three of which are currently included in our PPA price sample, due to lack of sufficient information on the others) illustrates this expansion of the market to the Southeast:

- In October 2014, Georgia Power announced long-term PPAs with four "smaller" PV projects totaling 76.5 MW and six "larger" projects totaling 439 MW. Although pricing for individual projects has not been disclosed, the average PPA price among the "smaller" projects is reportedly $65/MWh.
- In February 2015, the Tennessee Valley Authority announced that it had signed a 20-year PPA with an 80 MW PV project in Alabama at a price of $61/MWh.
- In April 2015, NextEra and Entergy Arkansas announced a PPA for the 81 MW Stuttgart Solar Project in Arkansas; the price is reportedly just north of $50/MWh.
- Highlighting yet another notable trend towards direct corporate purchases of renewable power, in June 2015, Community Energy and Amazon Web Services announced a PPA for an 80 MW PV project in Virginia (pricing was not disclosed).
- In July 2015, the Orlando (Florida) Utilities Commission announced a 20-year PPA with a 13 MW PV project priced at $70/MWh, which is less than half the $194/MWh it is paying for a similar 5.5 MW_{AC} project that came online in late 2011.

This trend – also evident in regional interconnection queues, as shown later in Figure 20 – is all the more notable because the Southeast has historically not seen much renewable energy development at all (other than in North Carolina, which has had an active solar market for a number of years, primarily featuring "avoided cost" PURPA contracts for projects of 5 MW or less that fall below our utility-scale size threshold), due in part to fewer state-level policies like renewable portfolio standards, as well as wind resource constraints. For example, unlike in much of the rest of the country, wind power has yet to gain much of a foothold in the Southeast – and may find it hard to compete with solar at the price levels evident in some of these solar contracts.

7. Conclusions and Future Outlook

Other than the SEGS I-IX parabolic trough CSP projects built in the 1980s, virtually no utility-scale PV, CPV, or CSP projects existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including storage – either achieving commercial operation or entering the commissioning phase. Although the operating history of many these newer PV, CPV, and CSP projects is still very limited, a critical mass of data nevertheless enables empirical analysis of this rapidly growing sector of the market.

This third edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since 2007-2009 (but perhaps showing signs of slowing), relatively modest O&M costs, solid performance with improving capacity factors, and record-low levelized PPA prices of around $40/MWh in some cases and under $50/MWh on average (again, with the steady decline over the years perhaps showing signs of slowing). Meanwhile, the other two utility-scale solar technologies – CPV and CSP – have also made strides in recent years, but are finding it difficult to compete in the United States with increasingly low-cost PV.[59]

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry – both in terms of volume and geographic distribution – over the next few years. Specifically, Figure 20 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2014.[60]

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

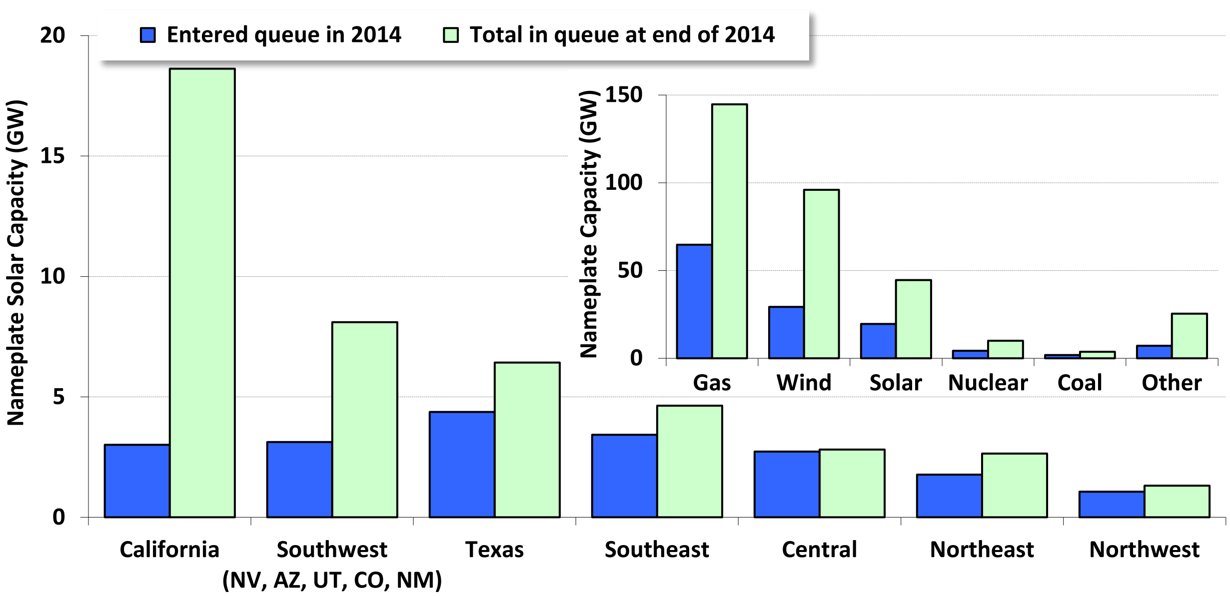
[59] Avian mortality has also emerged as an unexpected potential challenge to power tower technology in particular, but also to large PV projects that, from a distance, can reportedly resemble bodies of water and attract migrating waterfowl that are injured or killed while attempting to land in the solar field.

[60] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 86% of the U.S. total. Figure 20 only includes projects that were active in the queue at the end of 2014 but that had not yet been built; suspended projects are not included.

[61] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW

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

Even with this important caveat, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2014, there were 44.6 GW of solar power capacity (of any type – e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report – ***more than five times the installed utility-scale solar power capacity in our entire project population at that time.*** These 44.6 GW (19.5 GW of which first entered the queues in 2014) represented nearly 14% of all generating capacity within these selected queues at the time, in third place behind natural gas at 45% and wind at 30% (see Figure 20 inset). The end-of-2014 solar total is also more than 5 GW higher than the 39.5 GW of solar that were in the queues at the end of 2013, suggesting that the solar pipeline has been more than replenished over the past year, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2014, as well as the impending reversion of the 30% ITC to 10% scheduled for the end of 2016.



Source: Exeter Associates review of interconnection queue data

Figure 20. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 20 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides. Perhaps not surprisingly (given the map of solar resource and project location shown in Figure 3, earlier), 60% of the total solar capacity in the queues at the end of 2014 is within California (42%) and the Southwest region (18%). This combined 60% is down from 80% at the end of 2013, however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest. For example, 14% of the solar capacity in the queues at the end of 2014 resides in Texas, followed by 10% in the Southeast and 6% in each of the Central and Northeast regions.

range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences net out.

Moreover, in terms of *new* solar capacity entering the queue in 2014, Texas ranked first (22%), followed by the Southeast (18%), Southwest (16%), California (15%), and Central (14%) regions. As the competitiveness of solar continues to improve, the market is spreading to still-untapped parts of the country.

Though not all of the 44.6 GW of planned solar projects represented within Figure 20 will ultimately be built, presumably most of what is built will come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. To that end, as of the end of 2014, GTM/SEIA (2015) projected a utility-scale solar pipeline of 26.7 GW in 2015-2016 (9.1 GW in 2015 and 17.6 GW in 2016), 14.1 GW of which was already contracted (6 GW in 2015 and 8.1 GW in 2016). Even if only this 26.7 GW – or, for that matter, even just the contracted 14.1 GW portion – came online prior to 2017, it would still mean an unprecedented amount of new solar construction in 2015 and 2016. Of course, accompanying all of this new capacity will be substantial amounts of new operational data, which we will collect and analyze in future editions of this report.

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Data Sources

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

Technology Trends (Chapter 2):

Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), trade press articles

Installed Prices (Chapter 3):

Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL

O&M Costs (Chapter 4):

FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors (Chapter 5):

FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices (Chapter 6):

FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

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Exhibit PHM-8, Page 1 of 55

Utility-Scale Solar 2015

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

Authors: Mark Bolinger and Joachim Seel

Lawrence Berkeley National Laboratory

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August 2016

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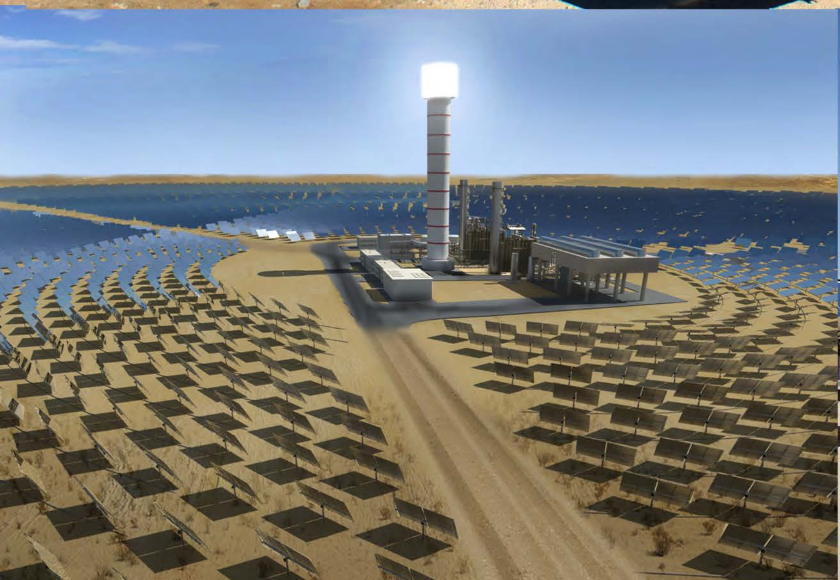

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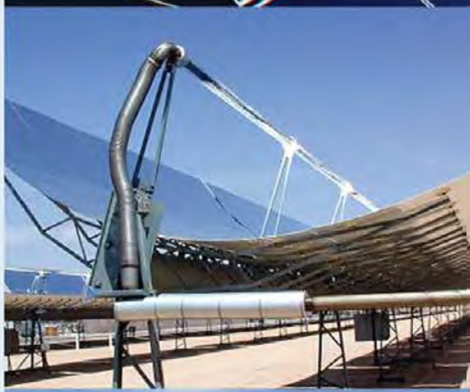


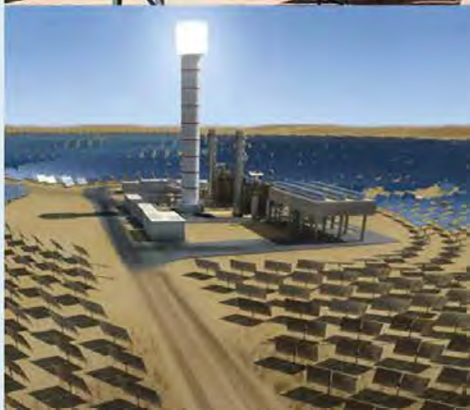


Table of Contents

List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
COD	Commercial Operation Date
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar (Thermal) Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	Energy Information Agency
EPC	Engineering, Procurement & Construction
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MW	Megawatt(s)
NCF	Net Capacity Factor
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PII	Permitting, Interconnection & Inspection
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SEGS	Solar Energy Generation Systems
TOD	Time-Of-Delivery

Executive Summary

The utility-scale solar sector—defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar power ("CSP") project that is larger than 5 MW_{AC} in capacity—has led the overall U.S. solar market in terms of installed capacity since 2012. It is expected to maintain its market-leading position for at least another five years, driven in part by December 2015's three-year extension of the 30% federal investment tax credit ("ITC") through 2019 (coupled with a favorable switch to a "start construction" rather than a "placed in service" eligibility requirement, and a gradual phase down of the credit to 10% by 2022). In fact, in 2016 alone, the utility-scale sector is projected to install *more than twice as much new capacity* as it ever has previously in a single year. This unprecedented boom makes it difficult, yet more important than ever, to stay abreast of the latest utility-scale market developments and trends.

This report—the fourth edition in an ongoing annual series—is intended to help meet this need, by providing in-depth, annually updated, data-driven analysis of the utility-scale solar project fleet in the United States. Drawing on empirical project-level data from a wide range of sources, this report analyzes not just installed project costs or prices—i.e., the traditional realm of most solar economic analyses—but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects throughout the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are also presented where appropriate.

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

- ***Installation Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and PPA price data analyzed later. For example, the use of solar tracking devices (overwhelmingly single-axis, east-west tracking—though a few dual-axis tracking projects have entered the population in recent years) continued to expand in 2015, particularly among thin-film (CdTe) projects, which had almost exclusively opted for fixed-tilt mounts prior to 2014. In a reflection of the ongoing geographic expansion of the market beyond the high-insolation Southwest, the average long-term insolation level across newly built project sites declined for the first time in 2015. Meanwhile, the average inverter loading ratio—i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating—has increased among more recent project vintages, as oversizing the array can boost generation (relative to the AC capacity), and hence revenue, particularly during the morning and evening shoulder periods. These trends should drive AC capacity factors higher among more recently built PV projects (confirmed by data for projects that were fully operational in 2015). Finally, 2015 saw one new CSP project (a 110 MW_{AC} solar tower project with 10 hours of thermal storage) and one new CPV project (an 18 MW_{AC} project with SunPower's new C7 technology) achieve commercial operation.
- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by nearly 60% since the 2007-2009 period, to \$2.7/W_{AC} (or \$2.1/W_{DC}) for projects completed in 2015. The lowest 20th percentile of projects within our 2015 sample (of 64 PV projects totaling 2,135 MW_{AC}) were priced at or below \$2.2/W_{AC}, with the lowest-priced

projects around $1.7/W_{AC}$. In comparison (though recognizing technological differences, including 10 hours of thermal storage), the single CSP power tower project that came online in 2015 was priced considerably higher than our PV sample, at $8.9/W_{AC}$.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs were in the neighborhood of $15/kW_{AC}$-year, or $7/MWh, in 2015. These numbers—from an extremely limited sample—include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.

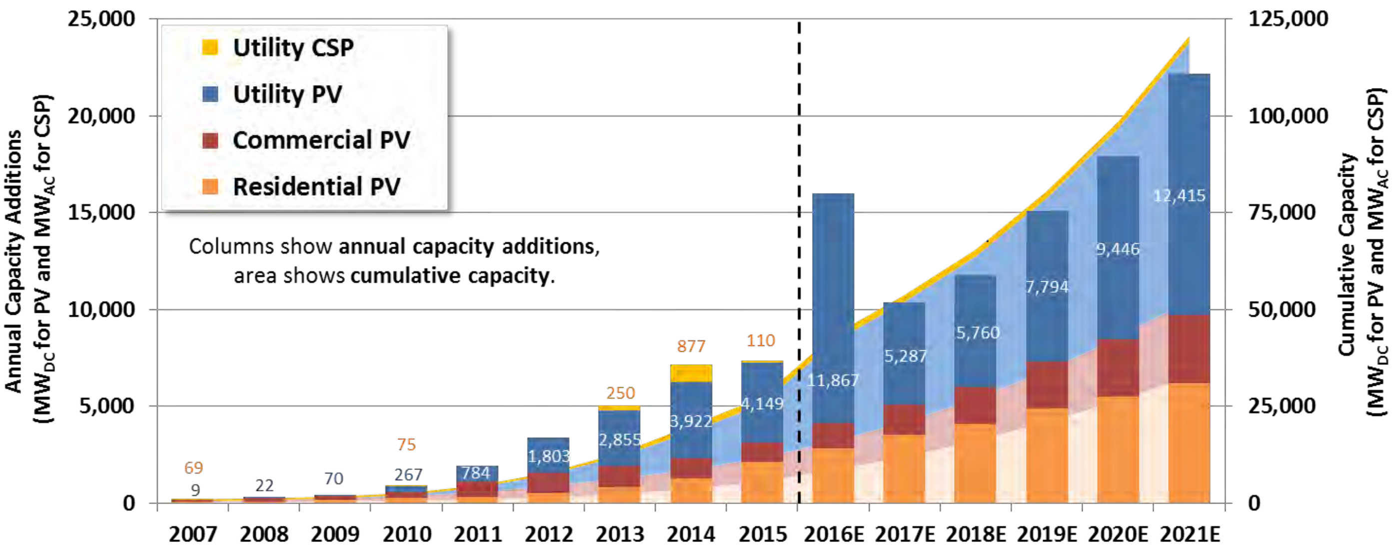
- ***Capacity Factors:*** The cumulative net AC capacity factors of individual projects in a sample of 170 PV projects totaling 5,907 MW_{AC} range widely, from 15.1% to 35.7%, with a sample mean of 25.7%, a median of 26.4%, and a capacity-weighted average of 27.6%. This project-level variation is based on a number of factors, including the strength of the solar resource at the project site, whether the array is mounted at a fixed tilt or on a tracking mechanism, the inverter loading ratio, the type of modules used (e.g., c-Si versus thin film), and likely degradation. Changes in at least the first three of these factors have driven mean capacity factors higher by project vintage over the last four years, to nearly 27% among 2014-vintage projects (whose first full operating year was in 2015). Turning to other technologies, two of the three CPV projects in our sample seem to be underperforming, relative to both similarly situated PV projects and ex-ante expectations. And the two CSP projects that had struggled to meet performance expectations in 2014 (Solana and Ivanpah) both increased their capacity factors considerably in 2015, though still not quite up to projected long-term, steady-state levels.

- ***PPA Prices:*** Driven by lower installed project prices and improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by $20-$30/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh per year evident in the 2014 and 2015 samples. Most PPAs in the 2015 sample—including many outside of California and the Southwest—are priced at or below $50/MWh levelized (in real 2015 dollars), with a few priced as aggressively as ~$30/MWh. Even at these low price levels, PV may still find it difficult to compete with *existing* gas-fired generation, given how low natural gas prices (and gas price expectations) have fallen over the past year. When stacked up against *new* gas-fired generation (i.e., including the recovery of up-front capital costs), PV looks more attractive—and in either case can also provide a hedge against possible future increases in fossil fuel costs.

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years. At the end of 2015 there was at least 56.8 GW of utility-scale solar power capacity making its way through interconnection queues across the nation (compared to 15.6 GW currently operational). Although most of this planned solar capacity is concentrated in California and the Southwest, the *growth* within these queues over the past two years—from 39.5 GW at the end of 2013 to 56.8 GW at the end of 2015—has come primarily from the up-and-coming Texas, Southeast, Central, and Northeast regions. Though not all of these projects will ultimately be built, the widening distribution of solar projects within these queues is as clear of a sign as any that the utility-scale market is maturing and expanding outside of its traditional high-insolation comfort zones.

1. Introduction

"Utility-scale solar" refers to large-scale photovoltaic ("PV"), concentrating photovoltaic ("CPV"), and concentrating solar power ("CSP") projects that typically sell solar electricity directly to utilities or other buyers, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets).[1] Although utility-scale CSP has a much longer history than utility-scale PV (or CPV),[2] and has seen substantial new deployment over the past few years,[3] the utility-scale solar market in the United States is now largely dominated by PV: there is currently significantly more PV than CSP capacity either operating (8.5x), under construction (27.9x), or under development (27.4x) in utility-scale projects (SEIA 2016). PV's dominance follows explosive growth in recent years, culminating in a massive spike in deployment of nearly 12 GW expected in 2016 (see Figure 1[4])—the latter an artifact of what had been, up until late-December 2015, a scheduled end-of-2016 reversion of the 30% federal investment tax credit ("ITC") to 10%.



Source: GTM/SEIA (2010-2016), LBNL's "Tracking the Sun" and "Utility-Scale Solar" databases

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

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[1] PV and CPV projects use silicon, cadmium-telluride, or other semi-conductor materials to directly convert sunlight into electricity through the photoelectric effect (with CPV using lenses to concentrate the sun's energy). In contrast, CSP projects typically use either parabolic trough or, more recently, "power tower" technology to produce steam that powers a conventional steam turbine.

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

[3] More than twice as much CSP capacity came online in the United States in 2013-2015 as in the previous 30 years.

[4] GTM/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box—*Defining "Utility-Scale"*—in this chapter for a discussion of different definitions of "utility-scale"). In addition, the PV capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box—*AC vs. DC*—at the start of Chapter 2 discusses why AC capacity ratings make more sense than DC for utility-scale PV projects). Despite these two inconsistencies, the data are nevertheless useful for the basic purpose of providing a general sense for the size of the utility-scale market (both historical and projected) and demonstrating relative trends between different market segments and technologies.

The December 2015 extension of the 30% ITC through 2019 brought several other changes as well. For non-residential projects (including utility-scale), the prior requirement that a project be "placed in service" (i.e., operational) by the reversion deadline was relaxed to enable projects that merely "start construction" by the deadline to also qualify. Moreover, rather than reverting from 30% directly to 10% in 2020, the credit will instead gradually phase down to 10% over several years: to 26%, 22%, and finally 10% for projects that start construction in 2020, 2021, and 2022 or thereafter, respectively.[5]

If not for this extension, projections of 2016 utility-scale PV deployment would be even higher than the nearly 12 GW_{DC} shown in Figure 1: various analysts project that ~1.8-2.5 GW_{DC} of utility-scale PV deployment will slip from 2016 into 2017 as a result of the relaxed deadline (Yozwiak 2015; Liebreich 2016; GTM Research 2015). Longer term, these same analysts project that the ITC extension will drive anywhere from 10-20 GW of incremental utility-scale PV deployment—i.e., above and beyond what had previously been expected prior to the extension—from 2017-2021. This unprecedented boom in the utility-scale market, expected to persist for at least the next five years, makes it increasingly difficult—yet, at the same time, more important than ever—to stay abreast of the latest developments and trends.

A Note on the Data Used in this Report

The data sources mined for this report are diverse, and vary depending on the type of data being analyzed, 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, trade press articles, and communication with project owners and developers. In most cases, the data are drawn from a sample, rather than the full universe, of solar power projects installed in the United States. Sample size varies depending on the technology (PV vs. CSP) and the type of data being analyzed, and not all projects have sufficiently complete data to be included in all data sets. Furthermore, the data vary in quality, both across and within data sources. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market data, with an emphasis on 2015; with some limited exceptions (including Figure 1 and Chapter 4), the report does not discuss forecasts or seek to project future trends.

This report—the fourth edition in an ongoing annual series—is designed to help identify and track important trends in the market by compiling and analyzing the latest empirical data from the rapidly growing fleet of utility-scale solar projects in the United States. As in past years, this fourth edition maintains our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box on the next page describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). In a change from previous years, this fourth edition breaks out coverage of PV and CSP into separate chapters (Chapters 2 and 3, respectively), to simplify reporting and enable readers who are more interested in just one of these technologies to more-quickly access what they need.[6] Within each of these two chapters, we first present technology-related trends (e.g., module and mounting preferences, inverter loading ratios, troughs vs. towers, etc.) among the existing fleet, before turning to empirical data on installed project costs or prices (in $/W terms), operation and maintenance ("O&M") costs, project performance (as measured by capacity factor), and power purchase agreement ("PPA") prices (the text box on this page—*A Note on the Data Used in this Report*—

[5] In addition, any project that qualified for a higher-than-10% ITC by starting construction prior to 2022 must also be placed in service by the end of 2023 in order to retain that higher credit; otherwise the credit drops to 10%.
[6] Select data pertaining to the few CPV projects in our sample continue to be presented, where warranted, along with the corresponding data for PV projects in Chapter 2.

provides information about the sources of these data). Chapter 4 then concludes with a brief look ahead.

Finally, we note that this report complements several other related studies and ongoing research activities at LBNL and elsewhere, most notably LBNL's annual *Tracking the Sun* report series, which each year analyzes the latest trends in residential and commercial PV project pricing, and NREL's PV system cost benchmarks, which are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (the text box on page 18 provides more information on NREL's utility-scale cost benchmarks). All of this work is funded by the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020. Most of LBNL's solar-related work can be found at emp.lbl.gov/projects/solar, while information on the SunShot Initiative can be found at energy.gov/eere/sunshot/sunshot-initiative.

Defining "Utility-Scale"

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

- Through its Form EIA-860, the Energy Information Administration ("EIA") collects and reports data on all generating plants larger than 1 MW, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA ("GTM/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FIT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 20 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC} (separately, ground-mounted PV projects of 5 MW_{AC} or less, along with roof-mounted systems of all sizes, are analyzed in LBNL's annual "Tracking the Sun" report series).

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

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

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

2. Utility-Scale Photovoltaics (PV)

At the end of 2015, 278 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects totaling 9,016 MW_{AC} were fully online in the United States.[7] Almost one-third of this capacity—i.e., 83 projects totaling 2,825 MW_{AC}—achieved commercial operation in 2015. The next five sections of this chapter analyze large samples of this population, focusing on technology trends, installed prices, operation and maintenance costs, capacity factors, and finally, PPA prices. Sample size varies by section, and not all projects have sufficiently complete data to be included in all five samples and sections.

For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms throughout this report, unless otherwise noted. In addition, all data involving currency are reported in constant or real U.S. dollars—in this edition, 2015 dollars[8]

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current ("DC") terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current ("AC") capacity rating—measured by the combined AC rating of the project's inverters—is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar power, or CSP) to which utility-scale PV is compared are described in AC terms—with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.

2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (described in more detail in later sections of this chapter, and portrayed in Figure 6). This increase in the "inverter loading ratio" boosts revenue and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the project's AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($/$W_{AC}$), operating costs ($/kW_{AC}-year), and AC capacity factor.

[7] Because of differences in how "utility-scale" is defined (e.g., see the text box at the end of Chapter 1), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM Research and SEIA (2016)) of the amount of utility-scale PV capacity online at the end of 2015. For instance, Figure 2 shows that a lower amount of capacity was installed in 2015 than in 2014, which stands in contrast to GTM Research and SEIA (2016), but is the result of these definitional differences (in addition to our policy of including in each calendar year only those PV projects that have become fully operational).

[8] Conversions between nominal and real dollars use the implicit gross domestic product ("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 2016* (Energy Information Administration 2016).

2.1 Technology and Installation Trends Among the PV Project Population (278 projects, 9,016 MW_{AC})

Before progressing to analysis of project-level data on installed prices, operating costs, capacity factors, and PPA prices, this section analyses trends in utility-scale PV project technology and configurations among the *entire population* of PV projects from which later data samples are drawn. The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or PPA price data presented and discussed in later sections.

The prevalence of tracking increased in 2015

Figure 2 characterizes the population capacity by mounting and module type, by delineating between projects with arrays mounted at a fixed tilt versus on tracking devices that follow the position of the sun,[9] and between projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium-telluride, or "CdTe") modules.

The percentage of newly built projects using tracking increased from 58% in 2014 to 65% in 2015, while in capacity terms the increase was much more significant, from 39% in 2014 to 70% in 2015. Although tracking has been the predominant mounting choice for c-Si projects for roughly five years now (as tracking costs have come down, reliability has improved, and the 30% ITC has helped defray the incremental up-front cost), the pairing of tracking with thin-film modules is a more recent phenomenon.[10] As was the case for the first time in 2014 (when 10 of the 15 new thin-film projects that came online used horizontal single-axis tracking), more new thin-film projects used tracking (11 projects) than fixed-tilt mounts (4 projects) in 2015 as well. Moreover, unlike in 2014, the *capacity* of new thin-film projects using tracking (334 MW_{AC}) also surpassed that of fixed-tilt thin-film projects (201 MW_{AC}) for the first time in 2015. As explained in footnote 10, thin-film's notably abrupt shift towards tracking has been driven in large part by significant improvements in the efficiency of CdTe modules in recent years.

Tracking aside, the prevalence of c-Si versus thin-film modules more generally has flip-flopped quite a bit in recent years, in part driven by a number of very large projects of each module type having come online in recent years, as well as the way in which we account for those projects

[9] All but seven of the 158 PV projects in the population that use tracking systems use horizontal single-axis trackers (which track the sun from east to west each day). In contrast, four recently built PV projects in Texas by OCI Solar, along with three CPV projects (and two CSP power tower projects described later in Chapter 3), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental costs (and risk of malfunction), depending on the PPA price.

[10] Prior to 2014, only two thin-film tracking projects had ever been built in the United States, in stark contrast to more than one hundred c-Si tracking projects. Tracking has not been as common among thin-film projects historically, largely because the lower efficiency of thin-film relative to c-Si modules in the past required more land area per nameplate MW—a disadvantage exacerbated by the use of trackers. In recent years, however, leading thin-film manufacturer First Solar has increased the efficiency of its CdTe modules at a faster pace than its multi-crystalline silicon competitors, such that at the end of 2015, First Solar's CdTe module efficiency was roughly on par with multi-crystalline at ~16% (though both still lag *mono*-crystalline modules by several percentage points—e.g., SunPower's utility-scale modules have efficiencies above 21%).

(i.e., including them in our project population only once they are fully online). First Solar, which manufactures CdTe modules, accounts for nearly all (93%) of the new thin-film capacity added to the project population in 2015, with the remainder (35 MW_{AC}) coming from Solar Frontier, a Japanese manufacturer of "CIGS" (copper indium gallium selenide) modules. In contrast, the new c-Si capacity installed in 2015 is more broadly distributed between SunPower (33%), Trina Solar (20%), and Jinko Solar (16%), with all other c-Si module manufacturers having a market share of less than 5% each.

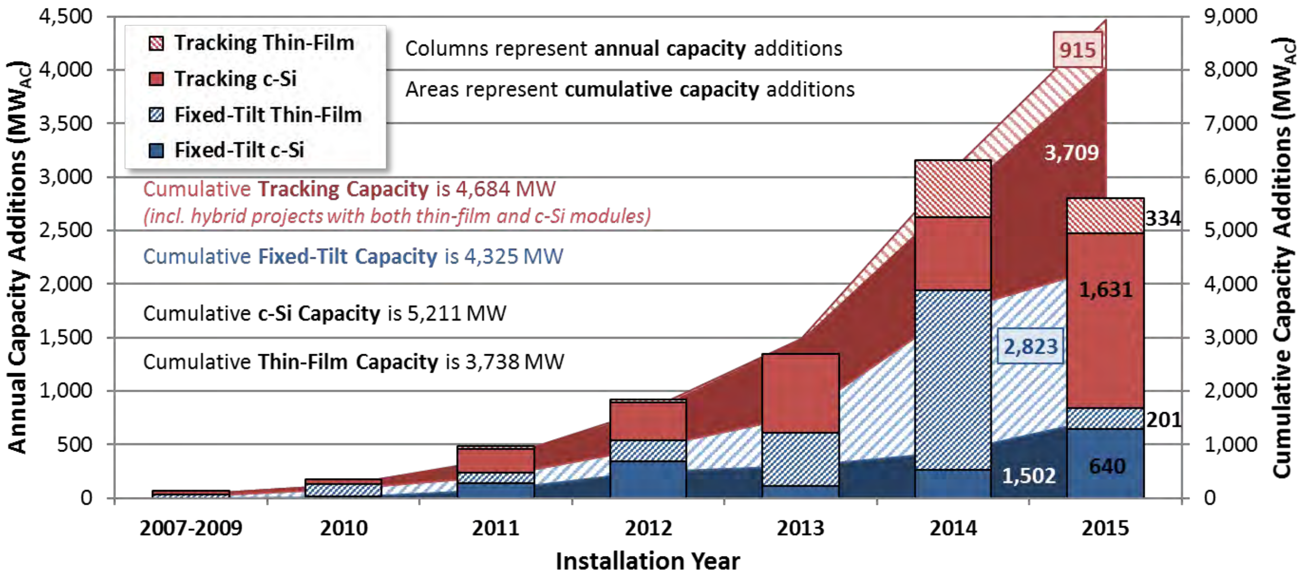

Figure 2. Capacity Shares of PV Module and Mounting Design by Installation Year

Figure 2 also breaks down the composition of *cumulative* installed capacity as of the end of 2015. For the first time since 2009, tracking projects held a slight majority at the end of 2015, with 52% of the cumulative installed capacity. In terms of module technology, due to its strong showing in 2015, c-Si regained the lead that it had lost the year before, making up 58% of the cumulative capacity installed at the end of 2015. Breaking these cumulative capacity statistics out by both module *and* mounting type, the most common combination was tracking c-Si (3,709 MW_{AC} from 129 projects), followed by fixed-tilt thin-film (2,823 MW_{AC} from 39 projects), fixed-tilt c-Si (1,502 MW_{AC} from 80 projects), and finally tracking thin-film (915 MW_{AC} from 25 projects).

Utility-scale PV continued to expand beyond California and the Southwest

Figure 3 overlays the location of every utility-scale PV project in the LBNL population (including four CPV projects) on a map of solar resource strength in the United States, as measured by global horizontal irradiance ("GHI").[11] Not surprisingly, most of the projects (and

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[11] Global Horizontal Irradiance (GHI) is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance (DNI) and diffuse horizontal irradiance (DIF). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).

capacity) in the population are located in California and the Southwest, where the solar resource is the strongest and where state-level policies (such as renewable portfolio standards, and in some cases state-level tax credits) have encouraged utility-scale solar development. Similar state-level policies have also driven utility-scale PV deployment in various states along the east coast and in the Midwest, despite the solar resource not being as strong. Figure 3 also defines regions that will be used for regional analysis later in this report.

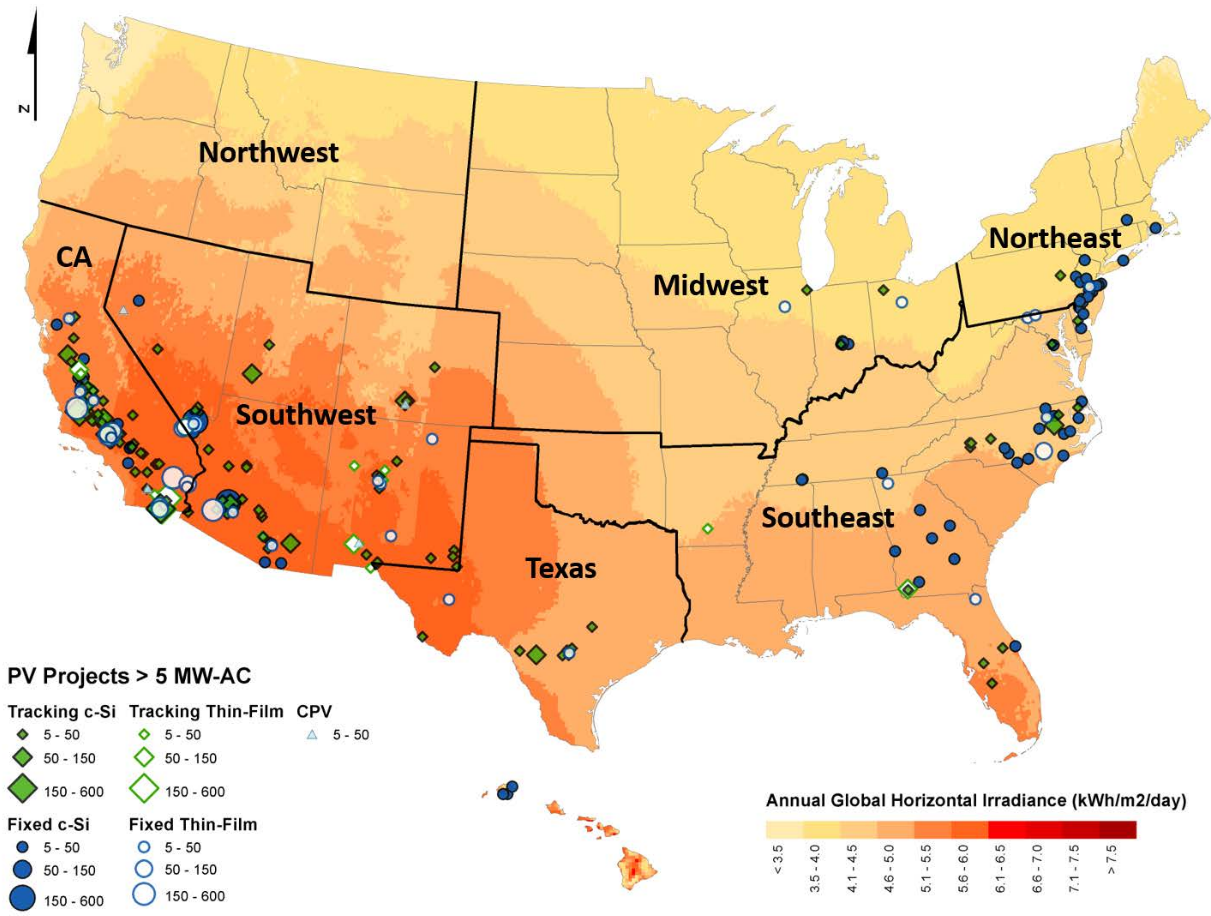

Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale PV Project Locations

2015 was a particularly strong year of growth for utility-scale PV outside of the traditional strongholds of California and the Southwest. The rest of the country contributed 28% of new utility-scale solar capacity in 2015, its highest share since 2011. Although California (56%) and the Southwest (26%) together still hold a clear lead in cumulative capacity, that lead declined from 86% in 2014 to 82% in 2015.

Notable new entrants on the map are Utah, where two larger projects totaling 130 MW_{AC} were completed in 2015 (propelling the state to tenth place in terms of cumulative installed capacity) and Arkansas, with its first utility-scale PV project of 13 MW_{AC}. Strong percentage growth occurred in North Carolina (quadrupling its previous capacity with 15 new projects, including a few that are much larger than the previous 20 MW_{AC} maximum), Georgia (nearly tripling its previous capacity with 6 new projects totaling 177 MW_{AC}), and Nevada (more than doubling its previous capacity with 4 new projects totaling 349 MW_{AC}).

Because some of these up-and-coming utility-scale PV states would barely show up if broken out on their own, Figure 4 lumps them together in demonstrating how the utility-scale market has been broadening beyond the historical capacity leaders of California and the Southwest. Specifically, 9 states outside of California and the Southwest added 28% of the newly installed capacity in 2015, an increase from the 8 such states that added only 8% of new capacity in 2014 and 5 such states that added 11% of new capacity in 2013.

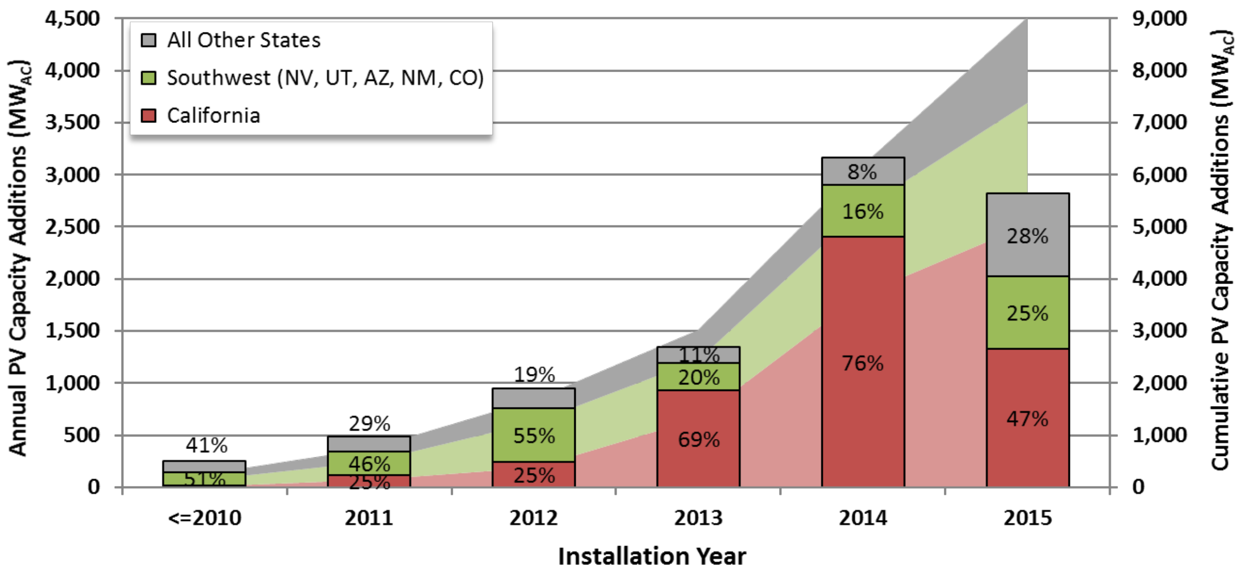

Figure 4. Annual and Cumulative Capacity Additions in California, the Southwest and Other States

The eastward expansion of utility-scale PV is reflected in the buildout of lower-insolation sites

Figure 3 above provides a static map of *where* and in what type of solar resource regime utility-scale solar projects within the population are located. But knowing *when* each of these projects was built—and hence how the average resource quality of the project fleet has evolved over time—is also useful, for example, to help explain observed trends in project-level capacity factors by project vintage (explored later in Section 2.4).

Figure 5 addresses this question by showing the capacity-weighted average GHI (in $kWh/m^2/day$) among utility-scale PV projects built in a given year, both for all projects (the solid black line with circle markers) and broken out by fixed-tilt versus tracking projects. Historically, the capacity-weighted average GHI of all utility-scale PV projects has increased steadily with project vintage, suggesting an ongoing build-out of large projects located in the solar-rich Southwest and California. As mentioned above, though, 2015 marked a deviation from this trend, resulting for the first time in a *decrease* in the capacity-weighted average solar resource among new projects. This decrease highlights the growing influence of regions outside of California and the Southwest.

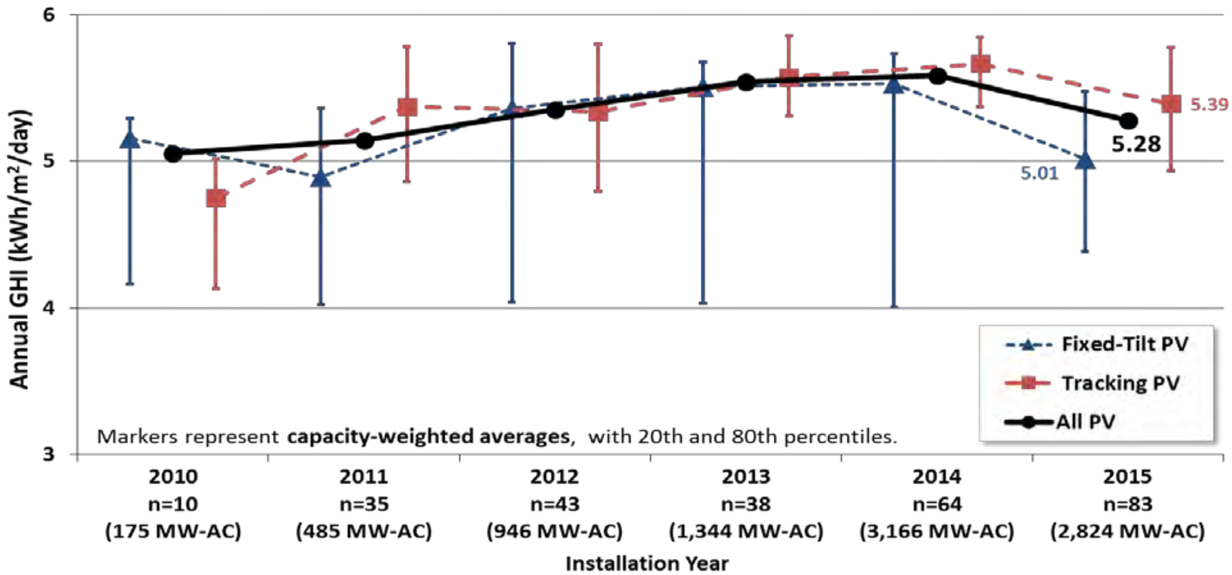

Figure 5. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

Moreover, the map in Figure 3 shows a preponderance of tracking projects (both c-Si and, more recently, thin-film) in the sunny Southwest and California, compared to primarily fixed-tilt c-Si projects in the lower-irradiance East. This dichotomy can also be seen in Figure 5 via the notable differences between the 20th percentile GHI numbers for fixed-tilt and tracking projects, with the former commonly as low as 4 kWh/m^2/day across most vintages, compared to much higher levels for tracking projects. The wide range of insolation among fixed-tilt projects reflects the fact that most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects (often using CdTe thin-film technology[12]) have also been built in high-GHI areas like California and the Southwest. In contrast, tracking projects have historically been concentrated in California and the Southwest, but have more recently also been deployed in other, less-sunny regions.

Developers continued to favor larger module arrays relative to inverter capacity

Another project-level characteristic that can influence both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[13] With the cost of PV modules having dropped precipitously (more rapidly than the cost of inverters), many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters

[12] The apparent preference for thin-film (primarily CdTe) modules in Desert Southwest projects is driven primarily by CdTe's greater tolerance for high-temperature environments (as well as relatively low land prices in the desert, which helped to mitigate CdTe's historical efficiency deficit). In its online blog (First Solar 2015), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at high/normal operating temperatures, due to its lower power temperature coefficient of -0.25% to -0.29%/°C (compared to something more like -0.40%/°C for most c-Si modules).

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

operate closer to (or at) full capacity for a greater percentage of the day, which—like tracking—boosts the capacity factor,[14] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production periods).[15] The resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to sunny summer months).

Figure 6 shows the capacity-weighted average ILR among projects built in each year, both for the total PV project population (solid black line with circle markers) and broken out by fixed-tilt versus tracking projects. Across all projects, the average ILR has increased significantly over time, from around 1.2 in 2010 to 1.31 in 2015. The slight dip in 2014 is partly attributable to a number of very large projects that had been under construction for several years finally achieving full commercial operation in 2014; some of these projects have lower ILRs than their more-recently designed counterparts.

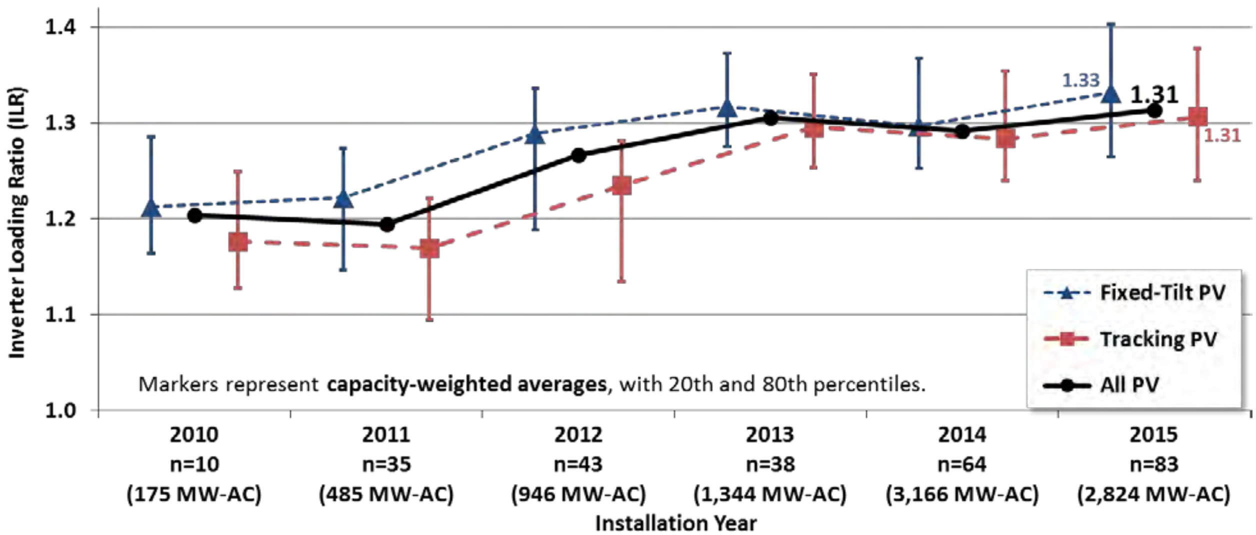

Figure 6. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

Fixed-tilt projects generally feature higher ILRs than tracking projects (statistics for 2014 were influenced by a few large fixed-tilt projects with lower ILRs). This finding is consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, "tracking-like" daily production profile. One particular fixed-tilt project built in 2015 even featured a new confirmed ILR maximum among our sample of 1.67, up significantly from the previous maximum of 1.50. That said, ILRs above 1.45 are fairly rare.

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[14] 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.

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

2.2 Installed Project Prices (240 projects, 8,045 MW_{AC})

This section analyzes installed price data from a large sample of the overall utility-scale PV project population described in the previous section.[16] It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by module type (c-Si vs. thin-film vs. CPV), mounting type (fixed-tilt vs. tracking), and system size. A text box at the end of this section compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

Sources of installed price information include the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, and finally, the trade press (e.g., Greentech Media, Mercom Capital Group). All prices are reported in real 2015 dollars.

In general, only fully operational projects for which all individual phases were in operation at the end of 2015 are included in the sample[17]—i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2016 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent reductions in component costs or other changes in market conditions.[18] For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV, and may differ from the average installed prices reported elsewhere (Fu et al. 2016; GTM Research and SEIA 2016). That said, the text box at the end of this section suggests fairly good agreement between our empirical installed price data and other published modeling estimates.

Our sample of 240 PV (and CPV) projects totaling 8,045 MW_{AC} for which installed price estimates are available represents 86% of the total number of PV projects and 89% of the amount of capacity in the overall PV project population described in Section 2.1. Focusing just on those PV projects that achieved commercial operation in 2015, our sample of 64 projects totaling 2,135 MW_{AC} represents 77% and 76% of the total number of 2015 projects and capacity in the population, respectively.

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[16] 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 financing transaction), or alternatively the fair market value of a given project—i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.

[17] In contrast, later sections of this chapter do present data for individual phases of projects that are online, or (in the case of Section 2.5 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

[18] This reasoning may partially explain why the decline in installed prices presented in this chapter has seemingly not kept pace with the decline in PPA prices reported later in Section 2.5.

Median prices fell to $2.7/W_{AC}$ ($2.1/W_{DC}$) in 2015

Figure 7 shows installed price trends for PV (and CPV) projects completed from 2007 through 2015 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is often reported in $/$W_{DC}$ terms as well (Barbose and Darghouth 2016; GTM Research and SEIA 2016). As noted in the text box (*AC vs. DC*) at the beginning of this chapter, however, this report analyzes utility-scale solar in AC terms. Figure 7 shows installed prices in both $/$W_{DC}$ and $/$W_{AC}$ terms in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this chapter, however, as well as the rest of this document, report data exclusively in AC terms, unless otherwise noted.

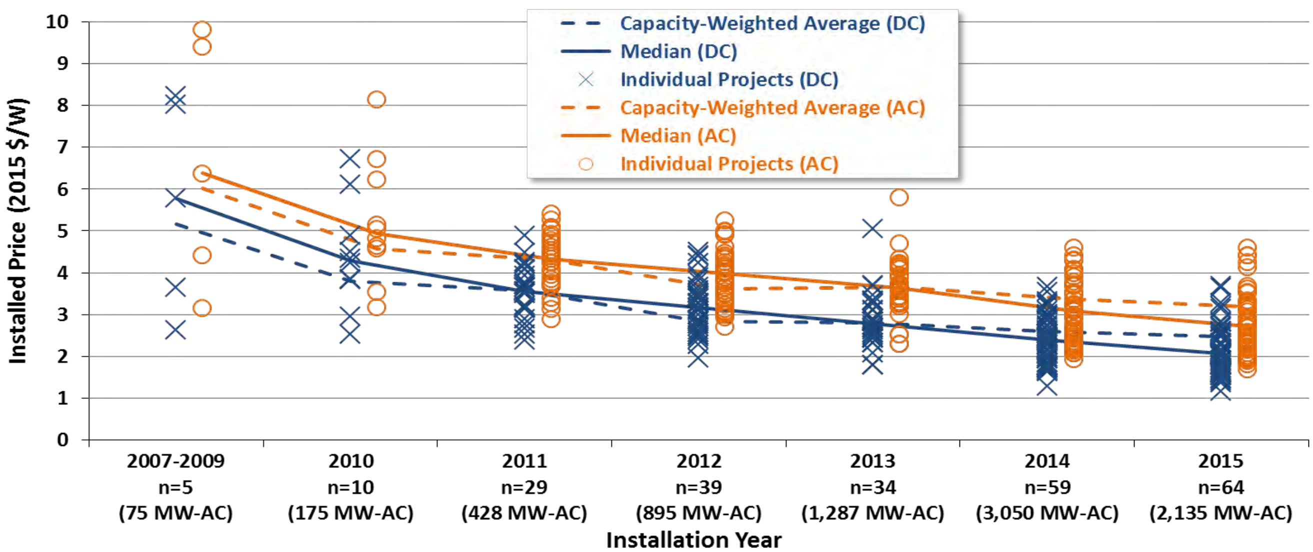


Figure 7. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

As shown, the median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $2.7/$W_{AC}$ (or $2.1/$W_{DC}$) in 2015. This represents a price decline of nearly 60% since the 2007-2009 period (and 45% since 2010). The lowest-priced projects in our 2015 sample of 64 PV projects were ~$1.7/$W_{AC}$ (~$1.2/$W_{DC}$), with the lowest 20^{th} percentile of projects falling from $2.3/$W_{AC}$ in 2014 to $2.2/$W_{AC}$ in 2015 (i.e., from $1.8/$W_{DC}$ to $1.6/$W_{DC}$).

In contrast, capacity-weighted average prices (dashed lines) have declined more slowly since 2012, to $3.2/$W_{AC}$ (or $2.5/$W_{DC}$) in 2015. That the capacity-weighted average price has been above the median price since 2013—the opposite of what one would expect for a technology like PV that should enjoy economies of scale—can be explained by a number of very large PV projects that have been under construction for several years but that only achieved final commercial operation in 2014 and 2015 (at which point they entered our installed price sample). These projects may have signed EPC contracts several years ago, perhaps at significantly higher prices than some of their smaller and more-nimble counterparts that started construction more recently.[19]

[19] For example, within our PPA price sample (described later in Section 2.5), the longest span between PPA execution date (as a proxy for EPC contract execution date) and commercial operation date for projects that came

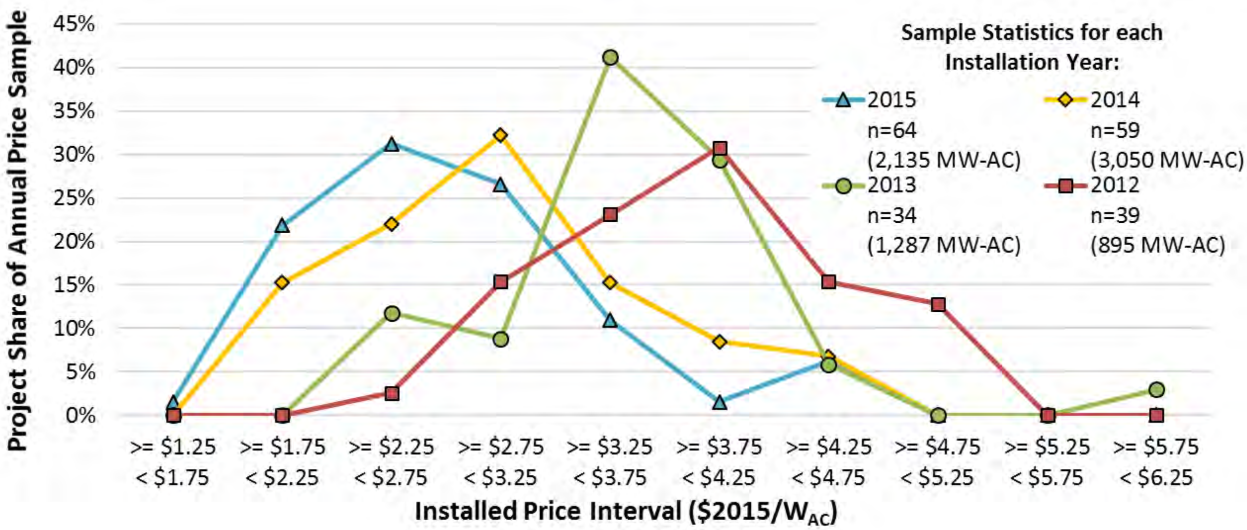


Figure 8. Distribution of Installed Prices by Installation Year

Figure 8 shows histograms drawn from the same sample, with an emphasis on the changing distribution of installed prices (which are reported only in $\$/W_{AC}$ terms from here on) over the last four years. The steady decline in installed prices by project vintage is evident as the mode of the sample (i.e., the price bin with the most projects, forming the "peak" of each curve) shifts to the left with each successive year. Additionally, the portion of the sample that falls into relatively high-priced bins (e.g., $\$3.75$-$\$5.75/W_{AC}$) decreases with each successive vintage, while the portion that falls into relatively low-priced bins (e.g., $\$1.25$-$\$2.75/W_{AC}$) increases. The "width" of the curves also narrows somewhat over time, indicating that the pricing within each successive vintage becomes less heterogeneous.

Tracking projects often command a price premium over fixed-tilt installations

While median prices in the sample have declined over time,[20] Figures 7 and 8 show that there remains a considerable spread in individual project prices within each year. The overall variation in prices may be partially attributable to differences in module and mounting type—i.e.,

online in 2015 is nearly 5 years, with the average lag for systems larger than 100 MW_{AC} being 4 ½ years, compared to 2 years for systems smaller than 100 MW_{AC}. Because of their size, very large projects continued to dominate the capacity-weighted average price in 2015 (three projects larger than 100 MW_{AC} represent 33% of the capacity additions in our price sample, but only 5% of new projects, in 2015). More detail on installed prices for these three projects is provided in Figure 11 towards the end of this section.

[20] Although in general we prefer capacity-weighted averages over medians, the rest of this section focuses on medians rather than capacity-weighted averages in order to avoid the apparent distortion seen in 2014 and 2015 of Figure 7. Whereas medians (and simple means) tell us about the typical project, capacity-weighted averages tell us more about the typical unit of capacity (e.g., the typical MW). Throughout most of this report, we are interested in analyzing the U.S. solar market in its entirety—e.g., deriving a representative installed price per unit of capacity (rather than per project), or a representative capacity factor or PPA price per MWh for the US fleet as a whole—and therefore tend to favor capacity-weighted averages over medians (or simple means). Given the apparent distortion noted above, however, as well as our increasing sample size over time (which lends itself more readily to medians), the use of medians seems more appropriate for this section—and will also align this report more closely with reported median prices for the residential and commercial PV systems in LBNL's companion *Tracking the Sun* series (see Barbose and Darghouth 2016).

whether PV projects use c-Si or thin-film modules, and whether those modules are mounted at a fixed tilt or on a tracking system.

Figure 9 breaks out installed prices over time among these four combinations (and also includes the three CPV projects in the sample—but excludes one "hybrid" project that features a mix of module and/or mounting types, and does not fit neatly into these four combinations). In 2015, the median price was \$2.6/W_{AC} for fixed-tilt c-Si projects, \$2.8/W_{AC} for tracking c-Si projects, \$2.3/W_{AC} for fixed-tilt thin-film projects, and \$3.1/W_{AC} for tracking thin-film projects.

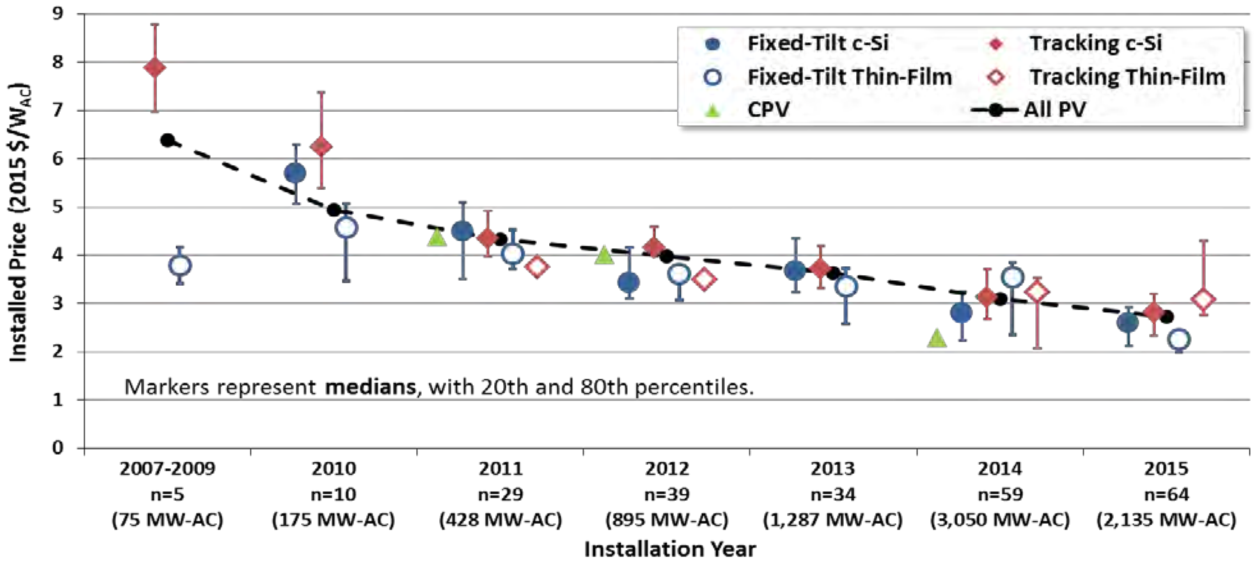


Figure 9. Installed Price of Utility-Scale PV (and CPV) Projects by Project Design and Installation Year

Although projects using c-Si modules were once significantly more expensive than projects using thin-film modules (e.g., by ~\$1.1/W_{AC} on average among fixed-tilt projects built in 2010, according to Figure 9), the average installed price of fixed-tilt c-Si and thin-film projects has more or less converged over time, led by the falling price of c-Si modules. As c-Si and thin-film prices have converged, the predominance of c-Si projects has grown in both the installed price sample and within the broader population, as described earlier in Section 2.1.

Tracking systems achieve a slight premium over fixed-tilt systems within the sample—a difference of about \$0.2/W_{AC} on average in 2015 among c-Si projects and as high as \$0.8/W_{AC} for recent thin-film projects. It should be noted, however, that the thin-film sample is much less robust, with just 5 fixed-tilt projects and 10 tracking projects, compared to 17 and 29, respectively, for c-Si. As such, the thin-film sample is more susceptible to potential price outliers.

Figure 10 presents the same data, but does not differentiate between c-Si and thin-film, and instead aggregates across module types. Viewed in this way, tracking projects in 2015 come at a cost premium of \$0.3/W_{AC} in comparison to fixed-tilt projects (similar to 2013 and 2014). This premium is supported by data recently released by the EIA, which for the first time published aggregate statistics from its new plant-level capital cost survey. Although so far the EIA has only released data for 2013, in that year the EIA's reported average installed price of tracking ($3.91/$W_{AC}$) and fixed-tilt projects ($3.55/$W_{AC}$) are similar to the LBNL medians shown in Figure 10 (Ray 2016), and show a premium of $0.37/$W_{AC}$ for tracking. Of course, as shown later in Section 2.4, this higher up-front expenditure for tracking results in greater energy production (and hence revenue), which outweighs the added cost.

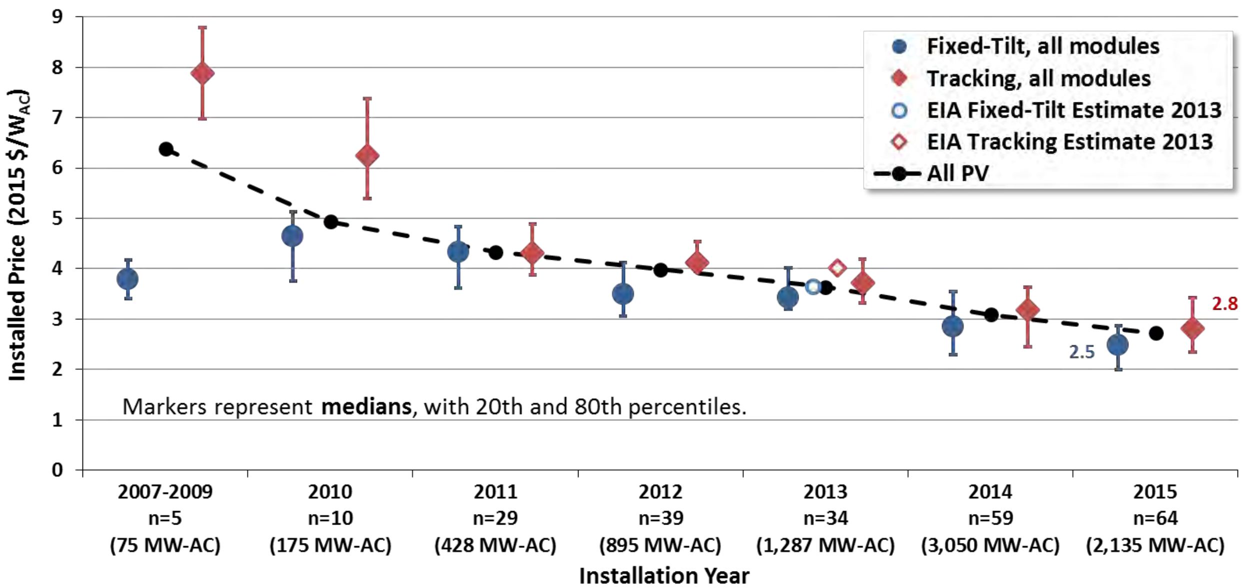


Figure 10. Installed Price of Utility-Scale PV by Mounting Type and Installation Year

Evidence of economies of scale continued to elude our sample

Differences in project size may also explain some of the variation in installed prices, as PV projects in the sample range from 5.5 MW_{AC} to 315 MW_{AC} (the 594 MW_{AC} Solar Star project is structured as a two-part project). Figure 11 investigates price trends by project size, focusing on just those PV projects in the sample that became fully operational in 2015, in order to minimize the potentially confounding influence of price reductions over time.

As shown, no consistent evidence of economies of scale can be found among the PV systems in our pricing sample that achieved commercial operation in 2015.[21] For example, there are no clear trends—either among the various mounting/module combinations (e.g., fixed-tilt c-Si) or for all projects in aggregate—among the first three project size bins, ranging from 5 MW_{AC} up to 100 MW_{AC}. One possible explanation for this seemingly counterintuitive finding is that economies of scale may be rather limited beyond what is already achieved by the standardized and modular "power blocks" (of up to several MW in size) that are offered by module manufacturers like SunPower and First Solar, and that are commonly used as the basis for larger

[21] These empirical findings are to some extent in conflict with recent modeling work from NREL (Fu et al. 2016) that analyzes the cost of projects in construction in Q1 2016 (that are not yet commercially operable). Excluding developer and EPC profit margins, NREL projects a $0.4/$W_{DC}$ cost advantage for a 100 MW_{DC} utility-scale PV plant over a 5 MW_{DC} project. However, the analysis does not correct for the potentially longer development times associated with the larger project, which could diminish the cost advantage when prices are indexed by COD (especially when significant interest for loans accrue over the development period).

projects. Alternatively, size-related cost savings may, in fact, be realized by EPC contractors, but will not necessarily show up in our installed price sample if they are not fully passed through to project owners in the form of lower prices. Or, to the extent that bulk procurement savings are realized at the developer rather than individual project level, economies of scale may be better measured by developer size than by project size. Finally, there may be some inconsistency in what costs or prices are included and reported by various projects; for example, some of the larger projects may include interconnection costs that are not present (or at least not reported) to the same degree by smaller projects.

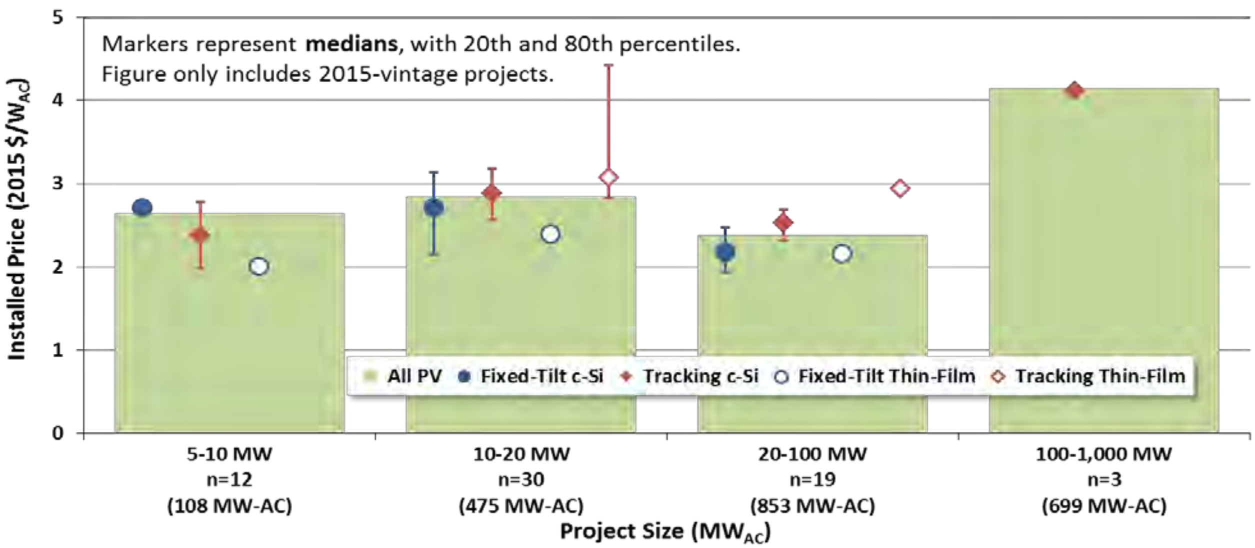


Figure 11. Installed Price of 2015 PV Projects by Size and Project Design

As was the case in last year's edition of this report (among the sample of 2014-vintage projects), the 2015 sample shown in Figure 11 once again suggests price *penalties* for projects larger than 100 MW_{AC}. Two factors may contribute to these apparent *dis*economies of scale for very large projects. First, most of these very large projects have been under construction for several years and may therefore reflect higher module and EPC costs from several years ago. For example, all projects larger than 100 MW_{AC} in our sample had a time lag between PPA execution and commercial operation date (COD) of more than 4 years, while all other projects had a time lag of less than 4 years (see also footnote 19). We find a correlation between a longer PPA-COD lag and a higher final installed project price, with an additional year of lag time resulting in a price premium of about \$0.5/W_{AC}. A second explanation may be that these mega-scale projects—some of which involve more than 2.5 million modules and project sites of nearly 10 square miles—often face greater administrative, regulatory, and interconnection costs than do smaller projects, and these costs are not fully offset by other size-driven savings like hardware procurement or a more-streamlined use of installation labor.

System prices vary by region

In addition to price variations due to technology and—notwithstanding the previous section—perhaps system size, prices also differ by geographic region. This variation may, in part, reflect the relative prevalence of different system design choices (e.g., the greater prevalence of tracking projects in California and the Southwest) that have cost implications. In addition, regional differences in labor and land costs, soil conditions or snow load (both of which have structural implications), or simply the balance of supply and demand, may also play a role. As shown in Figure 12 (which uses the regional definitions shown earlier in Figure 3), California is one of the most-expensive states in the United States, followed by the Northeast region, while the Southwest and Southeast feature similarly low prices that are below the national median. Due to the small number of observations, projects in Hawaii, Texas, and Indiana are not reported in Figure 12.

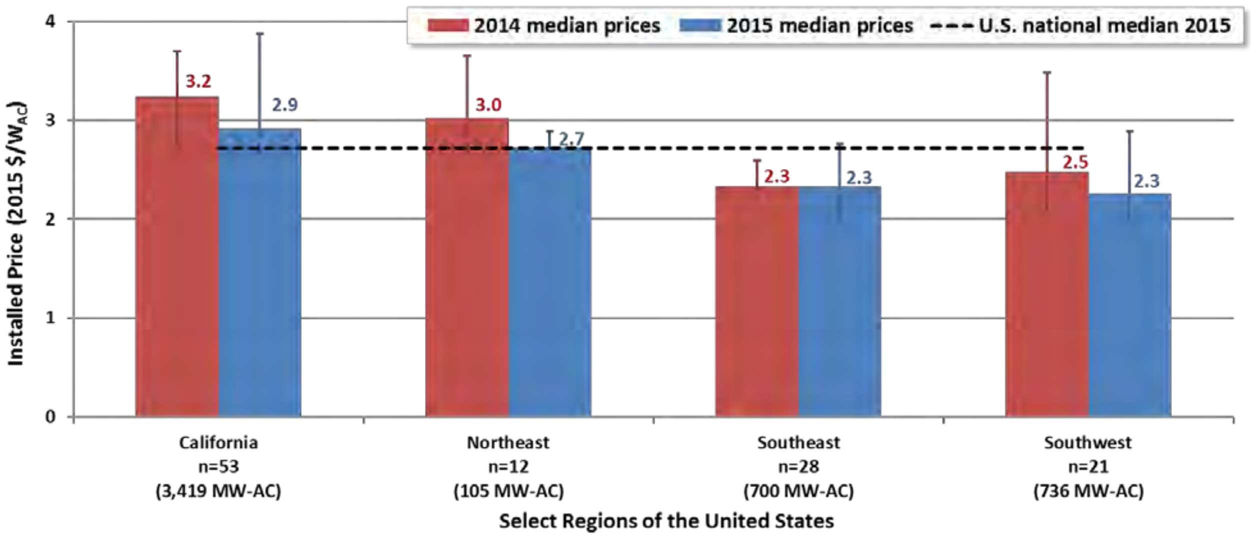


Figure 12. Median Installed PV Price by Region in 2015 and 2014

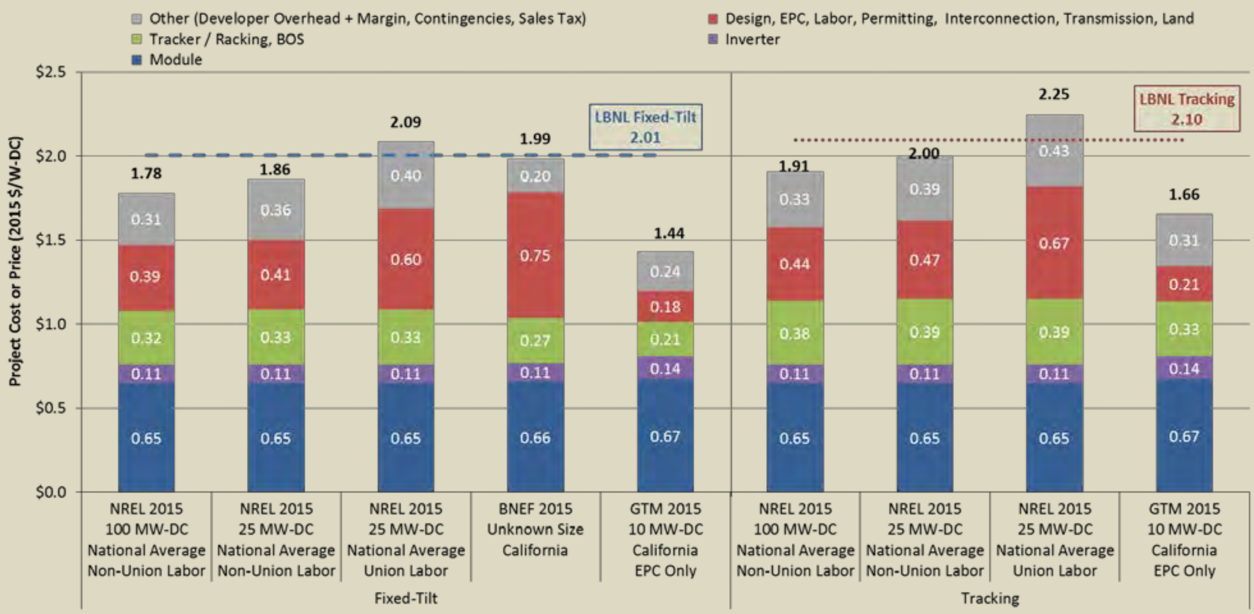
Finally, the text box on the next page compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this report generally represent empirical *top-down* price estimates gathered from sources (e.g., corporate financial filings, FERC filings, the Treasury's Section 1603 grant database) that typically do not provide more granular insight into component costs. In contrast, several publications by NREL (Fu et al. 2015), BNEF (Bloomberg New Energy Finance 2015), and Greentech Media (GTM Research and SEIA 2016) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed price. Each type of estimate has both strengths and weaknesses—e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check that captures the full range of diverse projects in the market, while bottom-up estimates provide more detail but rely on modeling, typically of idealized or "best in class" projects.

The figure below compares the top-down median 2015 prices for fixed-tilt ($2.01/$W_{DC}$) and tracking ($2.10/W_{DC}) projects in the LBNL sample with various bottom-up modeled cost estimates from the three sources noted above. Each bottom-up cost estimate is broken down into a common set of cost categories, which we defined rather broadly in order to capture slight differences in how each source reports costs (note that not all sources provided estimates for all cost categories). Finally, costs are shown exclusively in $/$W_{DC}$, which is how they are reported in these other sources.

Although GTM's relatively low cost estimates stand out as potential outliers, they represent only turnkey EPC costs—i.e., they exclude permitting, interconnection, and transmission costs, as well as developer overhead, fees, and profit margins—which perhaps explains the difference. LBNL's median fixed-tilt estimate of $2.01/$W_{DC}$ is quite close to BNEF's $1.99/$W_{DC}$, and for both fixed-tilt and tracking projects, LBNL's top-down empirical estimates fall in between NREL's bottom-up modeled estimates for a 25 MW_{DC} project built with either union or non-union labor. This relative positioning makes sense, given that LBNL's sample (which, incidentally, has a median project size of roughly 25 MW_{DC} for both fixed-tilt and tracking projects) reflects a mix of union and non-union labor, and has a fairly wide distribution of installed prices that encompasses the NREL single-point estimates. Finally, though not evident in the LBNL sample (as discussed earlier), modest economies of scale of less than $0.10/$W_{DC}$ are reflected in NREL's bottom-up modeled cost estimates for a 100 MW_{DC} project.



2.3 Operation and Maintenance Costs (30 projects, 546 MW_{AC})

In addition to up-front installed project costs or prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs to operate and maintain the generating plant itself. In other words, O&M costs—at least as reported here—exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Very few of the utility-scale solar projects that have been operating for more than a year are owned by regulated investor-owned utilities, which FERC requires to report (on Form 1) the O&M costs of the power plants that they own.[22] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). It also appears that, at least historically, some investor-owned utilities have not reported empirical O&M costs for individual solar projects, but instead have reported average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 1 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Year	PG&E		PNM		APS[23]		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	8	2	96	4	110	3
2013	100	6	30	4	136	6	110	3
2014	150	7	55	7	168	7	110	3
2015	150	7	95	11	191	9	110	3
Predominant Technology	fixed-tilt c-Si		4 fixed-tilt and 3 tracking thin-film, 4 tracking c-Si		primarily tracking c-Si		mix of c-Si and CSP	

Table 1. Operation and Maintenance Cost Sample (cumulative over time)

[22] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses"—namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).

[23] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 191 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 9 utility-scale solar plants with a combined capacity of 181 MW_{AC}.

Despite these limitations, Figure 13 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (PV, blue solid line) and $/MWh (PV, red dashed line). The bars represent both the lowest and the highest utility fleet-wide PV cost in each year. The yellow dotted line, meanwhile, shows the annual O&M costs of FP&L's 75 MW CSP plant (in $/kW-year terms only, because this project provides steam to a co-located combined cycle gas plant). Although this chapter focuses on PV projects, we've included this lone CSP plant here largely for the sake of expediency, given that it is the only CSP project for which we have O&M cost data. Not surprisingly, its O&M costs—which may not even be fully representative if they represent just the solar collector field and not the power block of the gas-fired combined cycle plant—are well above those of the PV projects shown.

Average O&M costs for the cumulative set of PV plants within this sample have steadily declined from about $31/kW$_{AC}$-year (or $19/MWh) in 2011 to about $16/kW$_{AC}$-year ($7/MWh) in 2015. This decline could potentially indicate that utilities are capturing economies of scale as their PV project fleets grow over time, although the significant drop from 2013 to 2014 may simply be a result of missing PG&E's costs for 2014 (PG&E's reported costs to the CPUC for 2012 and 2013 were above average, while costs reported to FERC for 2015 have come down to levels seen at other utilities). In 2015, all but five PV projects in the sample (i.e., in those instances where we have project-level rather than aggregate utility data) had O&M costs of less than $20/kW$_{AC}$-year (or $11/MWh), which is lower than medium-term projections by bond rating agencies (see the O&M cost section of Bolinger and Weaver (2014)).

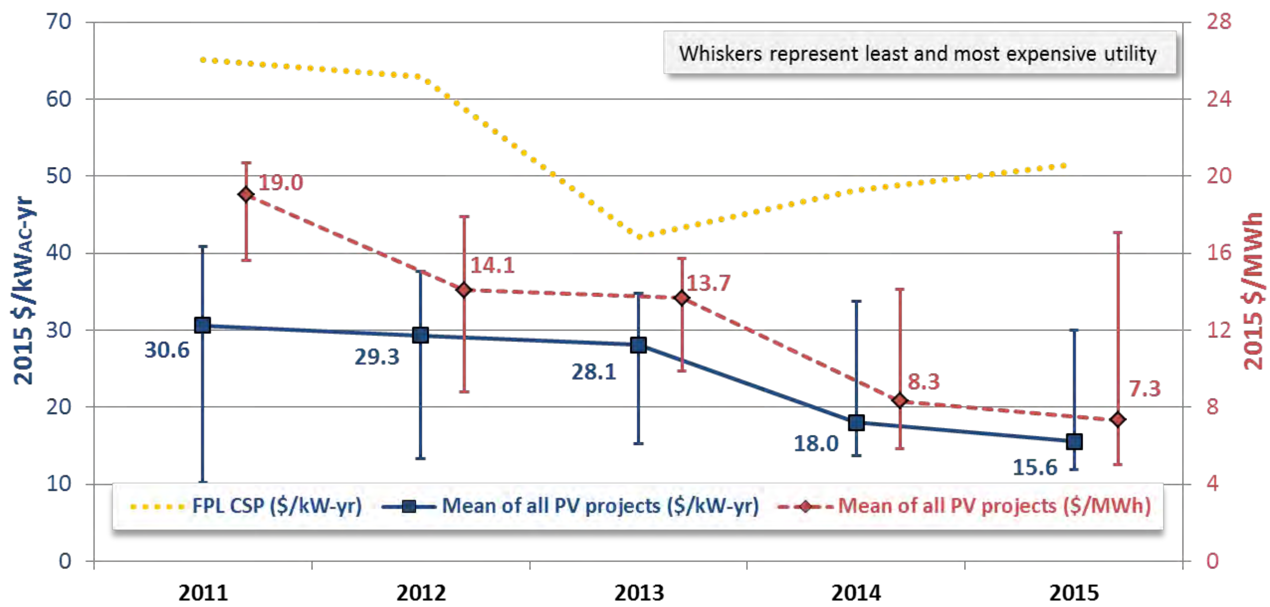


Figure 13. Empirical O&M Costs Over Time for Growing Cumulative Sample of Projects

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

2.4 Capacity Factors (170 projects, 5,907 MW_{AC})

At the close of 2015, at least 170 utility-scale PV projects in the United States had been operating for at least one full year, and in some cases for as many as eight years, thereby enabling the calculation of capacity factors.[24] Sourcing empirical net generation data from FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings, this chapter presents net AC capacity factor data for 170 PV projects totaling 5,907 MW_{AC}. This 5.9 GW_{AC} sample represents a substantial increase from the 3.2 GW_{AC} sample for which capacity factor data were analyzed in last year's edition of this report, driven in large part by new projects that began operating in 2014.

The capacity factors of individual projects in this sample range widely, from 15.1% to 35.7%, with a sample mean of 25.7%, a median of 26.4%, and a capacity-weighted average of 27.6%. Notably, these are *cumulative* capacity factors—i.e., calculated over as many years of data as are available for each individual project (up to a maximum of eight years, from 2008 to 2015, in this case), rather than for just a single year (though for projects completed in 2014, only a single year of data—2015—exists at present). Furthermore, they are also expressed in *net*, rather than *gross*, terms—i.e., they represent the output of the project net of its own consumption. Finally, they are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[25] yielding higher capacity factors than if reported in DC terms,[26] but allowing 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.

Wide range in capacity factors reflects differences in insolation, tracking, and ILR

Figure 14 presents the cumulative net AC capacity factors of each project in the sample (see the circle markers) broken out by three key project characteristics that recent statistical analysis (Bolinger et al. 2016) found to explain more than 90% of the variation in utility-scale PV project capacity factors: the estimated strength of the long-term solar resource at each site (measured in GHI with units $kWh/m^2/day$), whether the array is mounted at a fixed tilt or on a tracking mechanism, and the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR).[27] The blue-shaded columns show the mean cumulative capacity factor within each individual bin.

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[24] Because solar generation is seasonal (greater in the summer than in the winter), capacity factor calculations are performed in full-year increments.

[25] 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].

[26] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

[27] Instead of using capacity factors to gauge project performance, some analysts prefer to use the "performance ratio"— defined as "the ratio of the electricity generated to the electricity that would have been generated if the plant consistently converted sunlight to electricity at the level expected from the DC nameplate rating" (Dierauf et al. 2013). Because the performance ratio takes into account many of the variables explored in this section—e.g., fixed-tilt vs. tracking mounts, variations in insolation, DC capacity ratings, etc.—it can provide a more precise measure of how a project is performing *in light of its specific circumstances*. In this report, however, we are specifically interested in exploring the full range of empirical project performance experienced in the market, as well as the specific circumstances that drive it, and therefore prefer to focus on capacity factors, which do not filter out this information. In addition, some of the information required to calculate performance ratios—e.g., site-specific

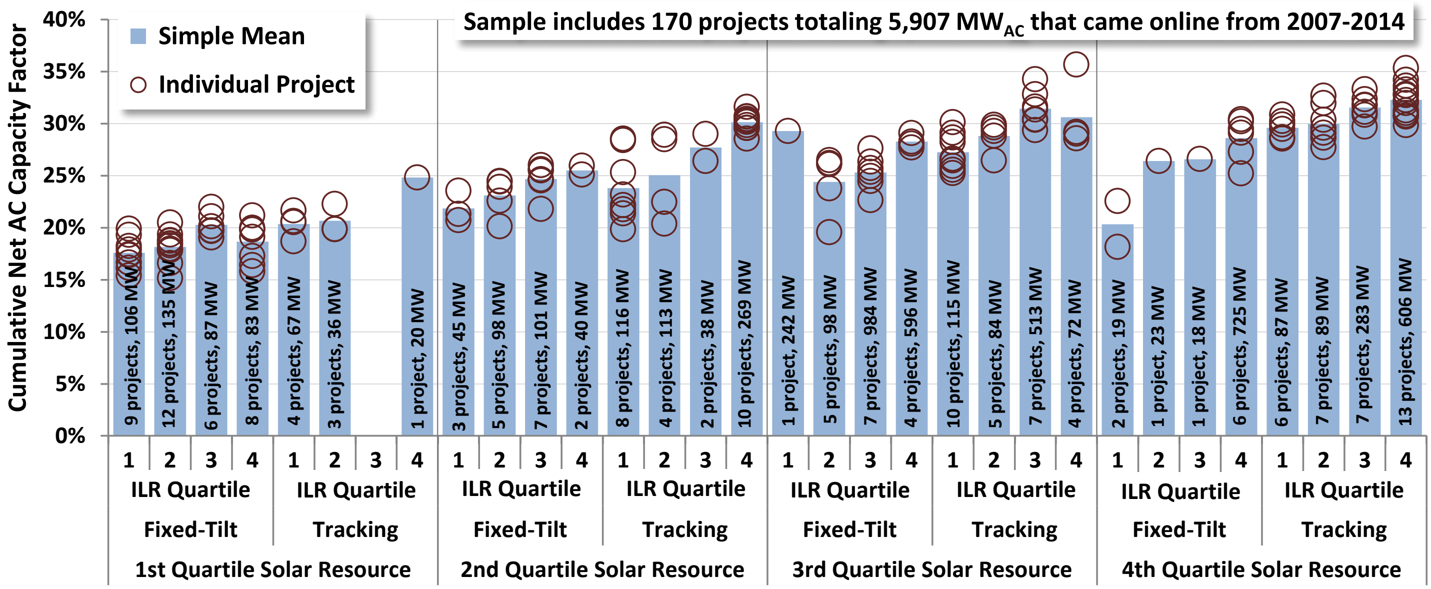

Figure 14. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio[28]

Each of the three drivers of capacity factor explored in Figure 14 is discussed in turn below.

- **Solar Resource:** Based on its geographic coordinates, each project in the sample is associated with a long-term average global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Figure 14 then parses the sample into solar resource quartiles that have the following thresholds: <4.74, 4.74-5.39, 5.39-5.79, and ≥5.79 kWh/m^2/day GHI. Roughly 43 projects fall into each resource quartile, though capacity is concentrated in the third (46%) and fourth (31%) quartiles. Not surprisingly, projects sited in stronger solar resource areas tend to have higher capacity factors, all else equal. The difference can be substantial: the mean capacity factors in the highest resource bin, for example, average 8 percentage points higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending from 3 to 10 percentage points depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** Seventy-nine projects in the sample (totaling 3,398 MW_{AC}) are mounted at a fixed-tilt, while the remaining ninety-one (totaling 2,509 MW_{AC}) utilize

insolation during the period of interest—is not readily accessible, making capacity factors a more expedient choice for this report.

[28] Figure 14 (as well as the rest of this section) excludes three CPV projects: the 5.04 MW_{AC} Hatch project (online since late-2011), the 30 MW_{AC} Cogentrix Alamosa project (online since early 2012), and the 6.3 MW_{AC} Desert Green project (online since late-2014). If plotted in Figure 14, these three projects would fall into the 29th, 10th, and 32nd bins, respectively, where their cumulative capacity factors of 18.4%, 23.9%, and 28.0% would—with the exception of Cogentrix Alamosa—fall below the respective PV bin means of 29.6%, 23.1%, and 32.3% (despite the CPV projects' use of dual-axis tracking, which should provide an advantage over the overwhelmingly single-axis PV sample). Based on this comparison to similarly situated PV projects, Hatch in particular seems to be underperforming (at just 18.4%, compared to the PV average of 29.6%). Earlier editions of this report provide additional details about the specifications and performance of the Hatch and Cogentrix Alamosa PV projects.

tracking (overwhelmingly single-axis east-west tracking, with the exception of two recent dual-axis tracking projects located in Texas). Tracking boosts average capacity factor by 2-5 percentage points on average (in absolute terms), depending on the resource quartile (i.e., 2% within the 2nd resource quartile, 5% in the 4th resource quartile), and 4% on average across all four resource quartiles. This finding that the benefit of tracking increases at higher insolation levels is consistent with results from Bolinger et al. (2016), and also explains why there are many more fixed-tilt (35) than tracking (8) projects in the lowest insolation quartile and many more tracking (33) than fixed-tilt (10) projects in the highest insolation quartile of Figure 14.

- **Inverter Loading Ratio (ILR):** Figure 14 breaks the sample down further into ILR quartiles: <1.19, 1.19-1.25, 1.25-1.30, and ≥1.30. Again, each quartile houses roughly 430 projects, but capacity is concentrated in the third (34%) and fourth (41%) quartiles. The effect of a higher ILR on average capacity factor is noticeable: across all four resource quartiles and fixed/tracking bins, the absolute percentage point difference in capacity factor between the fourth and first inverter loading ratio quartiles is as high as 8% (with an average of 4% across all bins).

Beyond the three drivers depicted in Figure 14, additional explanatory factors, such as array tilt and azimuth, will also play an obvious role in influencing capacity factors, particularly for fixed-tilt projects. Given that we focus only on ground-mounted utility-scale projects, however, our operating assumption is that these two fundamental parameters will be equally optimized across all projects to maximize energy production. Although this assumption may become increasingly tenuous as PV's grid penetration increases,[29] the fact that we lack solid data on project-level tilt and azimuth prevents further analysis of these two fundamental variables at present.

Finally, Figure 15 presents similar information as in Figure 14, but in a slightly different way. Instead of accounting for the strength of the solar resource via insolation quartiles (as in Figure 14), Figure 15 breaks out cumulative capacity factors for both fixed-tilt and tracking projects on a regional basis (with regions as defined earlier in Figure 3)—for those readers who prefer to think geographically rather than in terms of insolation. For the sake of simplicity, Figure 15 also ignores ILR differences. Given what we know about insolation levels regionally (see Figure 3), the results are not surprising: capacity factors are lowest in the Northeast and Midwest and highest in California and the Southwest. Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions (whereas the relatively low insolation Northeast and Midwest samples include more fixed-tilt than tracking projects).

[29] For example, at higher penetration levels, time-of-day pricing factors may shift to more-heavily favor the late afternoon hours, which could encourage developers of fixed-tilt projects to orient them in a more westerly direction.

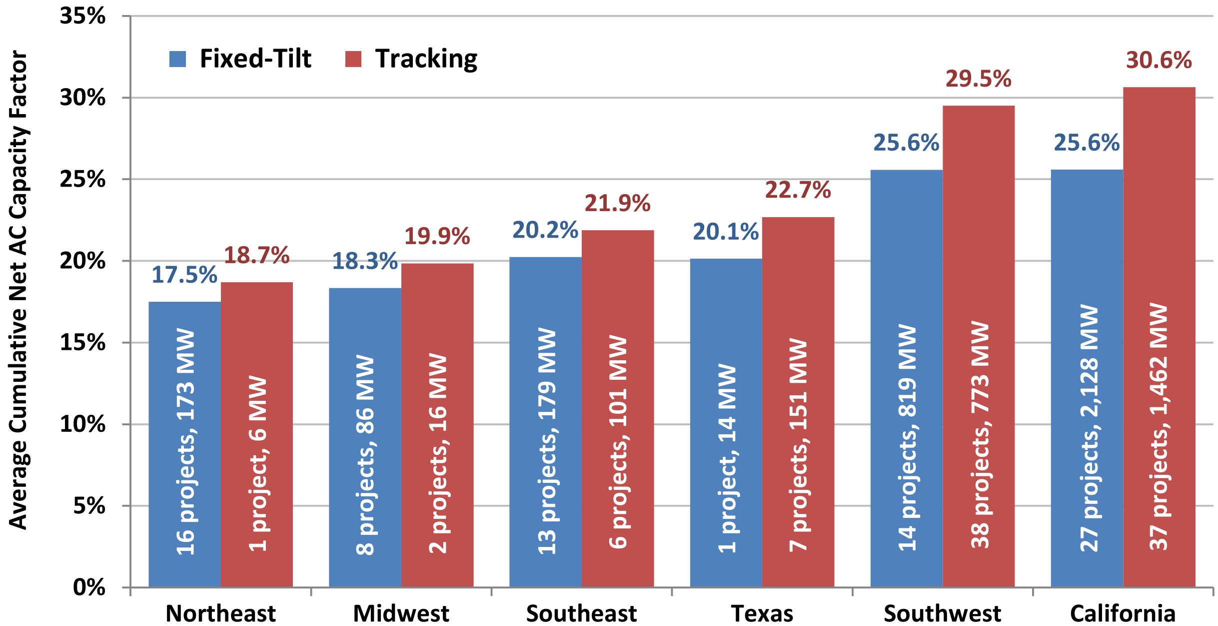

Figure 15. Cumulative Capacity Factor by Region and Fixed-Tilt vs. Tracking

More recent project vintages exhibit higher capacity factors

Although one might initially expect project vintage to be positively correlated with capacity factor because the efficiency of PV modules has improved over time, this is a red herring. As module efficiency increases, developers either use fewer modules 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 modules to boost the amount of capacity installed on a fixed amount of land (directly reducing at least $/W$_{DC}$ costs, if not also $/W$_{AC}$ costs). As a result, 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 examined above—e.g., towards higher inverter loading ratios or greater use of tracking, or a buildout of higher insolation sites.

Figure 16 tests this hypothesis by breaking out the average net capacity factor (both cumulative and in 2015) by project vintage across the sample of projects built from 2010 through 2014 (and by noting the relevant average project design parameters within each vintage). Following a notable step up from 2010- to 2011-vintage projects, driven by an increase in both tracking and mean GHI, the average cumulative capacity factor increases only slightly among 2012-vintage projects, given little movement in any of the three design parameters shown. A more-significant increase in average capacity factor is seen among 2013-vintage projects, corresponding to positive trends in all three design parameters, while 2014-vintage projects show essentially no change in average capacity factor, once again due to little movement in the underlying design parameters.

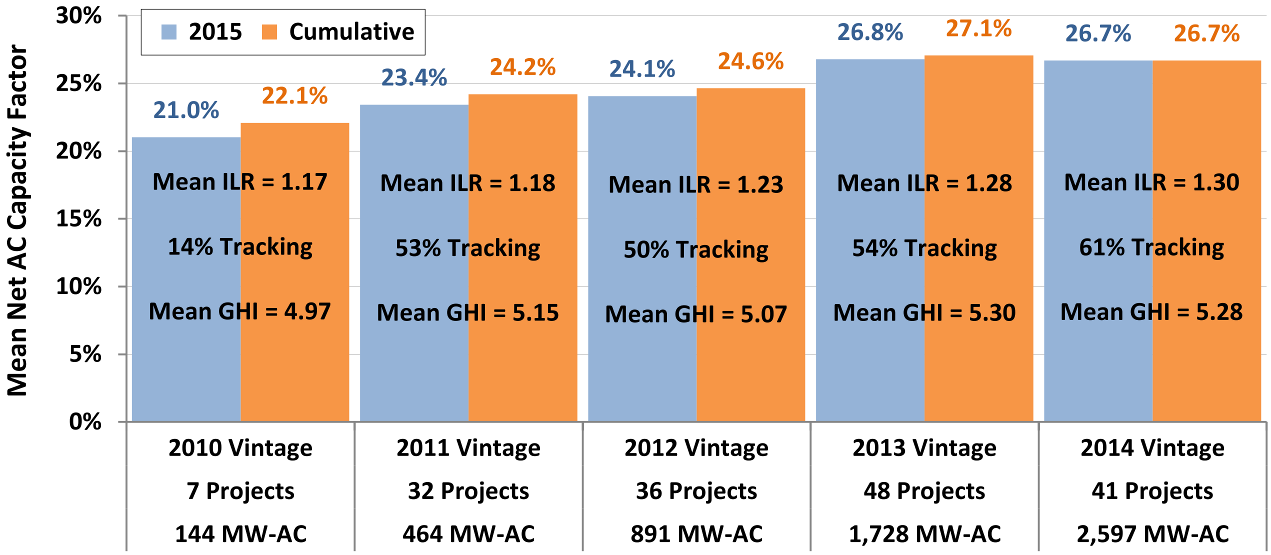

Figure 16. Cumulative and 2015 Capacity Factor by Project Vintage: 2010-2014 Projects

Two other factors could plausibly contribute to the general increase in average capacity factor by vintage seen in Figure 16: inter-year variation in the strength of the solar resource and performance degradation over time (as more recent project vintages have had less time to degrade). The former could play a role if insolation at these project sites were significantly stronger in more recent years (e.g., 2014-2015) than in earlier years (e.g., 2011-2013). If this were the case, then 2014-vintage projects, for example, might be expected to exhibit higher cumulative capacity factors than older projects, given that 2015 is the only applicable performance year for a 2014-vintage project.

Two findings, however, suggest that inter-year resource variation is *not* contributing to the upward trend seen in Figure 16. First, ex-post annual solar resource data (3Tier 2013; Vaisala 2014; Vaisala 2015, Vaisala 2016) finds that 2013-2015 were generally *below-normal* insolation years in California and the Southwest, where most utility-scale PV projects are located. Second, the blue columns in Figure 16 measure capacity factors across vintages during the same single year—2015—yet show essentially the same upward trend as the orange columns that measure cumulative capacity factors, suggesting that ILR, GHI, and tracking (and perhaps degradation—addressed in the next section) are the true drivers.

Degradation hard to measure at project level, but is seemingly within expectations

Finally, the possibility of performance degradation has been mentioned several times in the preceding text as a potential driver of project-level capacity factors. Unfortunately, degradation is difficult to assess at the project-level, in large part because its impact over limited time frames is likely to be rather modest and swamped by other factors. For example, over an 8-year period (i.e., the maximum number of full calendar years that any project in our sample has been operating to date), a representative degradation rate of 0.5%/year would reduce an initial net AC capacity factor of 30.0% to 29.0% in the eighth year. This single percentage point reduction in capacity factor over an eight-year period is rather trivial in relation to, and could easily be overwhelmed by, the impact of inter-year variations in the strength of the solar resource.

Nevertheless, some amount of degradation is widely expected (e.g., module manufacturers commonly build degradation into their performance guarantees, and many power purchase agreements for utility-scale PV projects also account for degradation when projecting output over time[30]), and so should not be ignored as a possible driver of cumulative capacity factor.

To that end, Figure 17 shows a time series of capacity factors by calendar year for the thirteen projects in our sample (denoted by the eight different states in which they are located) that have been operating for at least five years, and for as long as eight years. No attempt has been made to correct the data for inter-year variations in the solar resource; as such, interpretation of the trends is difficult. A general decline in capacity factor over time is evident, particularly during 2013-2015. But as mentioned earlier, 2013-15 reportedly featured below-normal insolation throughout much of the West and Southwest (where eight of these projects are located), particularly during the crucial summer months when solar generation peaks (3Tier 2013; Vaisala 2014; Vaisala 2015; Vaisala 2016). Meanwhile, the three eastern states in Figure 17—Ohio, Illinois, and Florida—were not hit quite as hard in 2015 (Vaisala 2016), which is reflected in their relatively stable capacity factors in that year. In summary, though Figure 17 presumably reflects some amount of degradation, the more prominent driver of lower capacity factors in recent years is likely to be the relatively poor insolation experienced throughout much of the country from 2013-15.

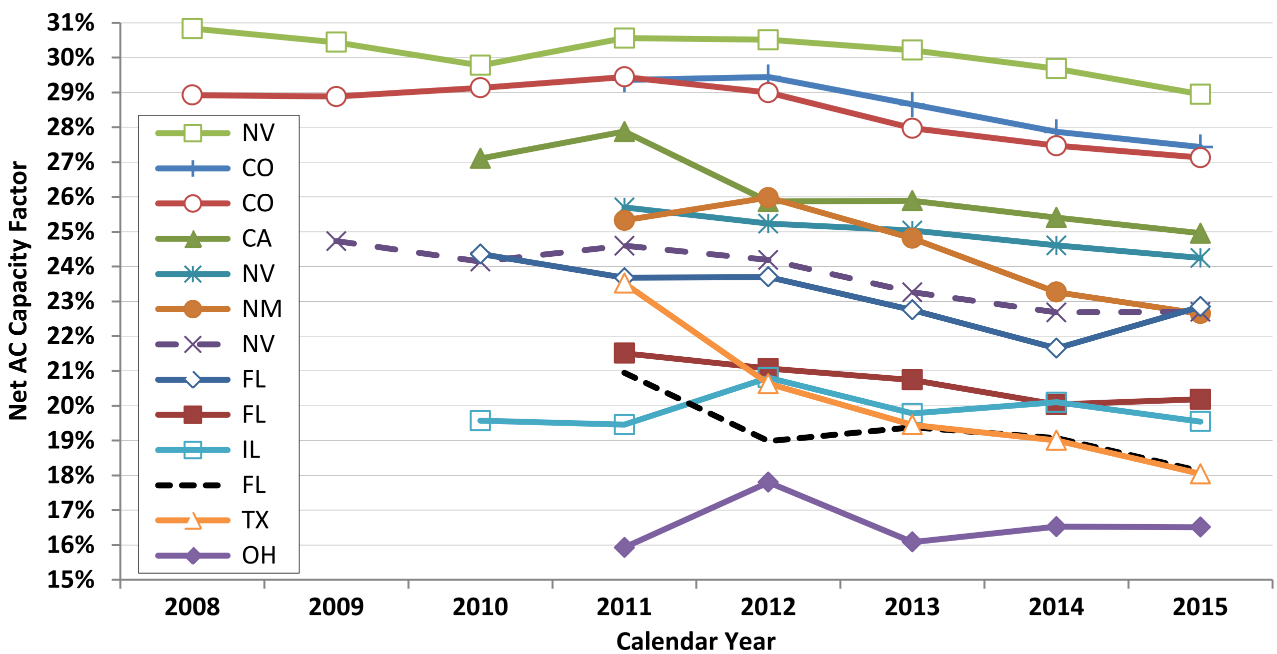

Figure 17. Capacity Factors by Calendar Year for 13 Projects with at least 5 Years of Performance History

30 For example, within a sub-sample of 29 utility-scale PV PPAs totaling 3,215 MW_{AC} that were collected for the next section of this report, degradation rates range from 0.25%-1.0% per year, with a sample mean of 0.6%/year and a median of 0.5%/year.

2.5 Power Purchase Agreement (PPA) Prices (136 contracts, 9,097 MW_{AC})

The cost of installing, operating, and maintaining a utility-scale PV project, along with its capacity factor—i.e., all of the factors that have been explored so far in this report—are key determinants of the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale PV projects in the U.S., including 136 contracts totaling 9,097 MW_{AC}.

The population from which this sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, 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 does not reflect the project's total revenue requirements (at least on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons—i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). The same holds true for "avoided cost" contracts with non-negotiated or "standard offer" pricing (also known as "PURPA" or "QF" contracts),[31] which are FiT-like in nature and, in some states, also involve unbundling RECs.

In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[32] 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) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[33]

[31] The Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978 and requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects smaller than 80 MW) at prices that represent their "avoided cost"—i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. In recent years, PURPA has come under fire in some states that are experiencing a large influx of wind and solar projects seeking avoided cost contracts (for more information, see the text box—*Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets*—in last year's edition of this report (Bolinger and Seel 2015)).

[32] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[33] 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 encourage solar power development specifically. 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

For each of the contracts in the sample,[34] we have collected the contractually locked-in PPA price data over the full term of the PPA,[35] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[36] 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[37]) these projects over the life of the contract—at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation)[38] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[39,40] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized levelized cost of energy ("LCOE").

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prices do not directly affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases—presumably to the upside.

[34] 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 two or more PPAs may be tied to a single project.

[35] The minimum PPA term in the sample is 3 years, though this contract (along with several other short-term contracts like it) covers just the first few years of a project that has a longer-term PPA with a different counterparty starting in 2019. The maximum PPA term is 34 years, the mean is 22.6 years, the median is 23.1 years, and the capacity-weighted average is 22.9 years.

[36] 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 2016* 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.

[37] 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.

[38] In addition to the other federal incentives listed, eleven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee did not affect the PPA price.

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

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

PPA prices have fallen dramatically, in all regions of the country

Figure 18 shows trends in the levelized (using a 7% real discount rate) PPA prices from the full PV contract sample over time. Each bubble in Figure 18 represents a single PPA, with the color of the bubble representing the region in which the underlying project is located,[41] 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).[42]

Figure 19, meanwhile, is exactly the same as Figure 18, except that it focuses only on those PPAs that were signed in 2014 or 2015. The purpose of Figure 19 is to provide greater resolution on the most-recent time period, which otherwise appears a bit crowded in Figure 18.

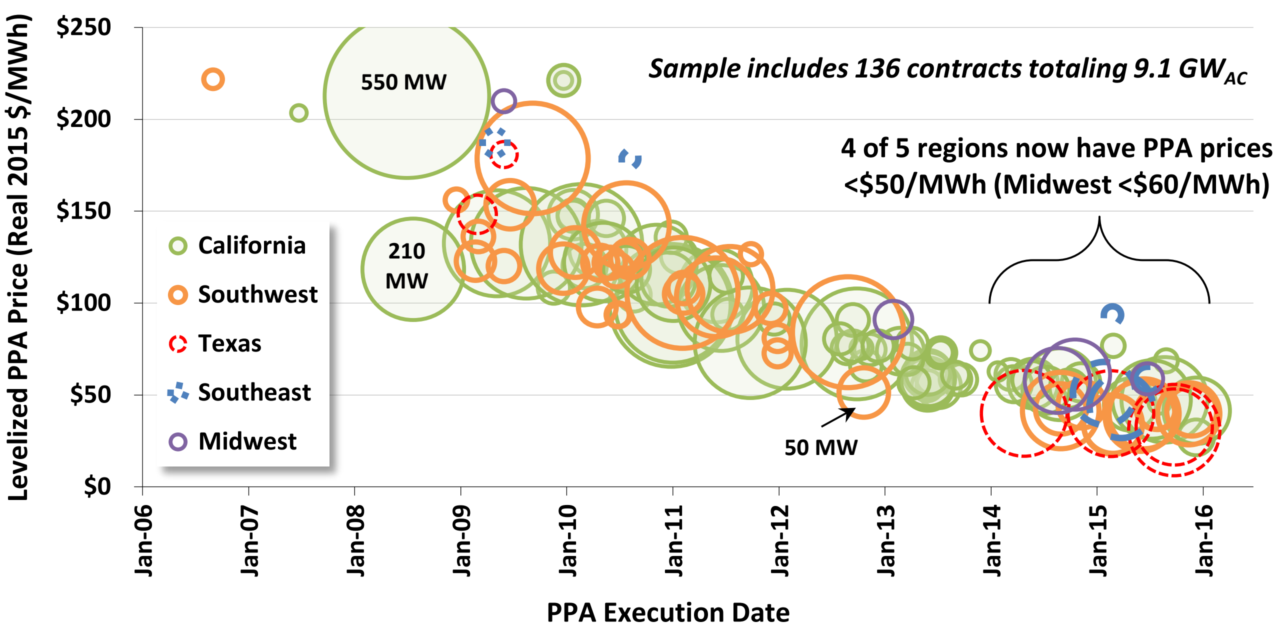


Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

[41] Figure 18 excludes the single northeastern PPA in our sample: a 32 MW_{AC} project on Long Island that was signed in June 2010 and that has a real levelized price of ~$286/MWh.

[42] Because PPA prices reflect market expectations at the time a PPA is executed—which could be two years or more in advance of when the project achieves commercial operation—the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices. For those interested in viewing average PPA prices by commercial operation date, however, Figure 21 breaks it out both ways.

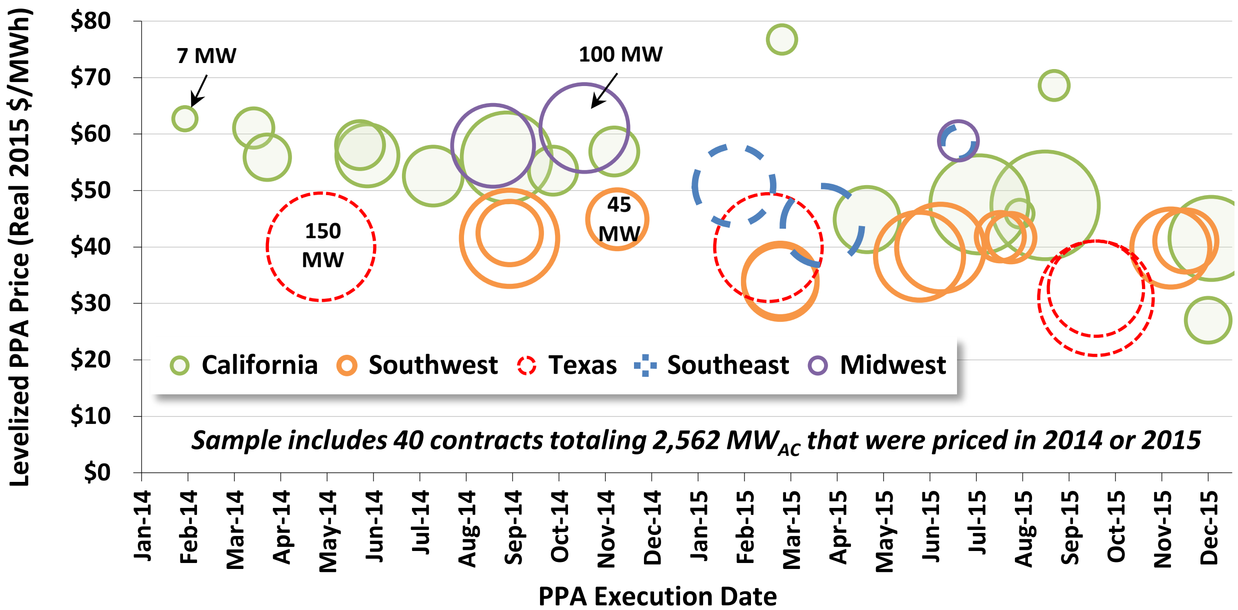


Figure 19. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2014 and 2015 Contracts Only

A number of aspects of Figures 18 and 19 are worth highlighting:

- ***PPA pricing has declined steadily and significantly over time.*** As recently as 2011, solar PPA prices in excess of $100/MWh were quite common. Barely five years later, most PPAs in the 2015 sample are priced at or below $50/MWh levelized (in real, 2015 dollars), with a few priced as aggressively as ~$30/MWh.

- ***Though California and the Southwest still dominate the sample, the market has expanded to other regions in recent years.*** Among the sub-sample of PPAs executed *after* 2013, 73% of the contracts representing 62% of the capacity are for projects located in either California or the Southwest, down significantly from 93% of the contracts representing 98% of the capacity within the sub-sample of PPAs executed *prior to* 2014. New markets include Texas (23% of post-2013 capacity in the sample), the Southeast (7%), and even the sun-challenged Midwest (8%).

- ***All five regions now feature relatively low PPA prices.*** Four of the five regions shown in Figures 18 and 19 are now home to PV projects with levelized PPA prices that are below $50/MWh, and three of these regions—California, the Southwest, and Texas—have contracts below $35/MWh levelized. Somewhat surprising, given the relative weakness of its solar resource, the Midwest is not too far behind, with several projects priced under $60/MWh—a price that only a year or two ago would have been considered aggressive even in much sunnier regions.

- ***PV is increasingly competitive with other renewable power options.*** In California and the Southwest in particular, pricing this low is, in some cases, competitive with in-region wind power.[43] This is especially the case when considering solar's on-peak generation profile, which can provide ~$25/MWh of TOD value relative to wind, at least at low levels of solar penetration in the electric grid.[44] Although the number of utility-scale PV and (especially) wind projects in the Southeast is still comparatively sparse, wind is likely to find it hard to compete with PV in this up-and-coming region as well.

- ***Smaller projects are equally competitive.*** Though there have recently been a number of large, low-priced contracts announced (particularly in Texas), smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are, in some cases, seemingly just as competitive as larger projects. In many states, very large projects often face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.

- ***Not all of these projects are online.*** Unlike other chapters of this report, which focus exclusively on operating projects (determined by commercial operation date), this chapter tracks PPA prices by *contract execution date*—which means including projects that are still in development—in order to provide a better picture of where the market is (or was) at any given point in time. As of June 2016, at least three quarters of all projects and capacity within the PPA sample were either partially or fully operating, with the remainder representing more-recently signed contracts for projects that had, prior to the ITC extension, been targeting a December 2016 commercial operation date. With the ITC extension having now eased the pressure somewhat, a number of these projects will likely lapse into 2017.

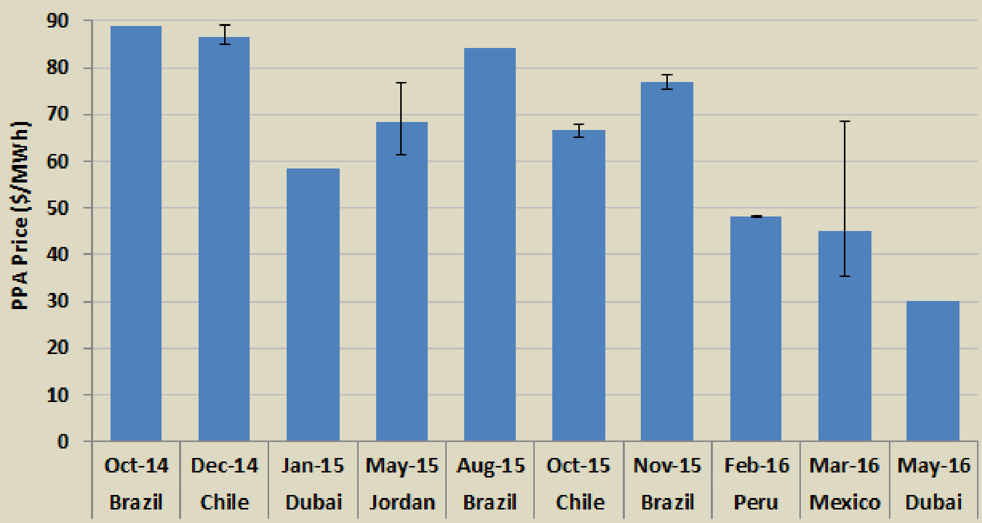
- ***There is no compelling reason to believe that projects still in development will not be built.*** Given that many of the lowest-priced contracts in the sample are from projects that are still in development, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown in Figure 19.[45] That said, the sample does not include any PPAs that have been terminated, and a recent spin-off modeling analysis (Bolinger, Weaver, and Zuboy 2015) finds that today's aggressive PPA prices can indeed pencil out using modeling assumptions that are based on best-in-class PV data presented in other sections of this report. Moreover, as described in a text box within last year's edition of this report (see *Solicitation Responses Reveal Deep Market at Low Prices* in

[43] See, for example, the text box in Bolinger and Weaver (2013) that compares the economics of the co-located Macho Springs wind and solar projects.
[44] For further explanation, see the text box titled *Estimating PV's TOD Value* in the 2013 edition of this report (Bolinger and Weaver 2014). Also note that the levelized PPA prices shown in Figures 18 and 19 (and throughout this chapter) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, PV's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the buyer.
[45] There is a history of solar project and PPA cancellations in California and elsewhere, 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 than outright termination.

Bolinger and Seel (2015)), these low prices do not appear to be one-off anomalies, as evidenced by the deep field of projects bidding into various solicitations at these low prices. Finally, as described in the text box on this page, recent experience in international markets suggests that the U.S. is not alone in enjoying record-low solar PPA prices; in fact, compared to some recently announced PPA prices in other countries, the U.S. market looks comparatively expensive.

Low International PPA Prices Reveal Expanding Global Market

Low PPA prices for utility-scale PV projects are not, of course, confined to the United States. The past two years have witnessed several successive announcements of low-priced solar PPAs in different parts of the world, each newly proclaiming to represent the world's cheapest solar power. The graph below summarizes many of these PPA prices, which have primarily resulted from competitive auctions in countries located in the sun-rich Middle East and North Africa (MENA) region or Latin America. The blue columns represent the average PPA price, and the error bars (if any) show the range of successful bids (no error bars either means that the auction cleared at a single price, like in Dubai, or else we could not find enough data to determine the proper range of prices, like in the first two Brazil auctions).



While these global PPA prices appear comparable to those in the U.S. (as described elsewhere in this chapter), an important distinction is that U.S. PPA prices reflect federal tax and other subsidies, while the global PPA prices presented in the graph are often presented as being "unsubsidized." That said, some of these PPAs do reflect various "soft" subsidies, such as low-cost financing or guarantees from development banks and/or sovereign wealth funds, or PPAs denominated in U.S. dollars to mitigate currency risk, for example. Without these soft subsidies, pricing would likely be higher than shown.

Although the presence of varying types and levels of both explicit and soft subsidies complicates an apples-to-apples comparison between international PPA prices, one potentially useful data point to inform the discussion is what the 30% ITC and accelerated tax depreciation equate to in PPA price terms. Results from a basic financial pro forma model suggest that a U.S. PV project that requires a levelized PPA price of $35.5/MWh (in real 2015 dollars, or $42.2/MWh levelized in nominal dollar terms) with the 30% ITC and 5-year accelerated depreciation in place would need to increase its levelized PPA price by ~$18/MWh (in real 2015 dollars, or by ~$21.3/MWh in nominal dollar terms) if the ITC were eliminated and the depreciation schedule was lengthened to 12-year straight line (the schedule allowable for natural gas power plants). In other words, without federal tax subsidies, this representative (at least in some parts of the U.S.) $35.50/MWh levelized PPA price would be more like $53.50/MWh. In this light, some of the more-recent "unsubsidized" PPA prices shown in the graph above—e.g., the sub-$30/MWh price out of Dubai or the $35.5/MWh winning bid in Mexico—look truly astounding indeed.

Figure 20 portrays the data from Figure 18 in a slightly different way, to more clearly illustrate the strong downward time trend in average pricing. The circle markers show the levelized PPA price of each individual contract grouped by the year in which the contract was signed (each circle in Figure 20 corresponds to a bubble in Figure 18), while the blue-shaded columns show the generation-weighted average of those individual levelized contract prices. Levelized PPA prices for utility-scale PV projects consistently fell by $20-$30/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples.[46] With levelized PPA prices now below $50/MWh on average (the 2015 sample has a generation-weighted average of $41/MWh, a simple mean of $47/MWh, and a median of $42/MWh), future average price declines are likely to be much smaller than in the past.

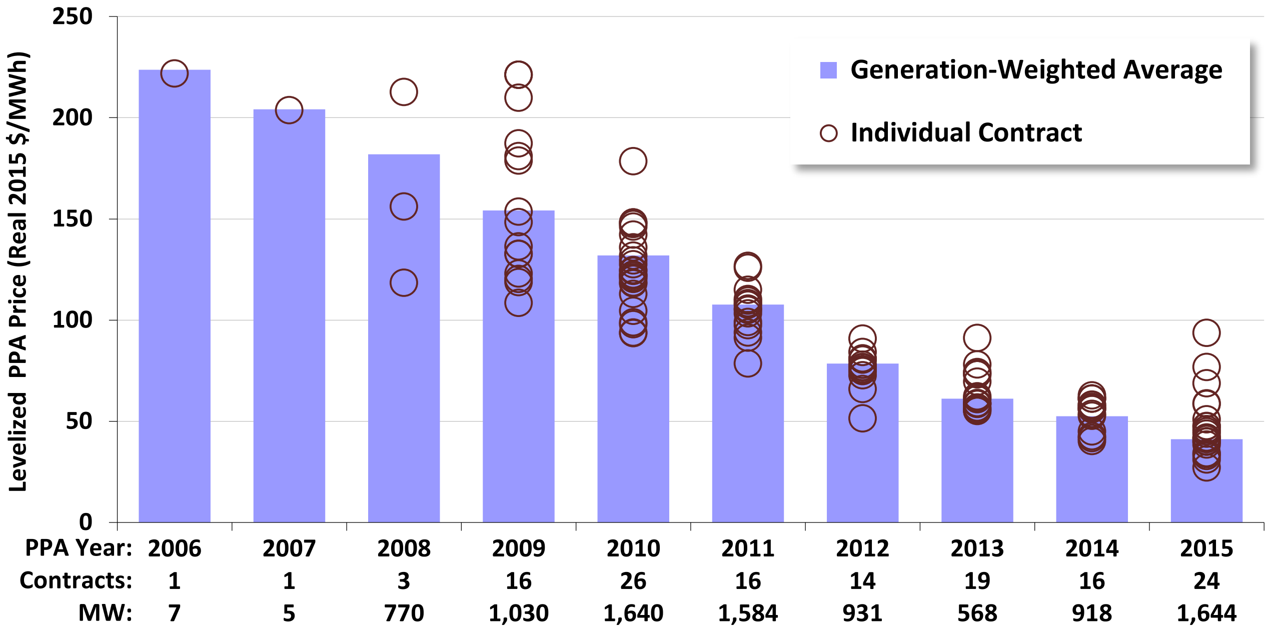


Figure 20. Levelized PV PPA Prices by Contract Vintage[47]

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[46] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength, tracking versus fixed-tilt, inverter loading ratio, and module type. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PPAs in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Section 2.2) that are recouped over time through greater energy yield (see Section 2.4), thereby potentially leaving the net effect on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico estimated (based on a review of 216 solar responses to its 2012 Renewable RFP) that—at least at that time—the average PPA price benefit of single-axis tracking was just $3/MWh, or less than 4% of a levelized PPA price in the mid-$70/MWh range (O'Connell 2013).

[47] Figure 20 excludes the two CPV projects in our sample. If included, they would both fall within the 2010 bin, at levelized prices of $109.3/MWh and $126.6/MWh—i.e., within the range of PV projects shown.

As noted earlier, some projects in our PPA price sample have not yet been built, and for those that have been built often a year or more can pass between when a PPA is signed and when the underlying project ultimately achieves commercial operation. As a result, the decline in PPA prices over time looks more erratic when viewed by commercial operation date (rather than by PPA execution date). The blue columns in Figure 21 are based on PPA execution date (and thus match those shown in Figure 20), while the orange columns show the generation-weighted average PPA price in the years in which each project achieved full commercial operation. Virtually all of the projects that had not come online by the end of 2015 had been targeting 2016 completion dates in order to capture the 30% ITC, but some construction schedules may have since lapsed in light of the December 2015 ITC extension, which—in addition to the fact that 2016 is still in progress—is why 2016 is labeled as provisional in the graph. Though the average levelized price of PPAs signed in 2015 is ~$40/MWh, the average levelized PPA price among projects that came online in 2015 is significantly higher at ~$85/MWh; this difference was even starker in 2014.

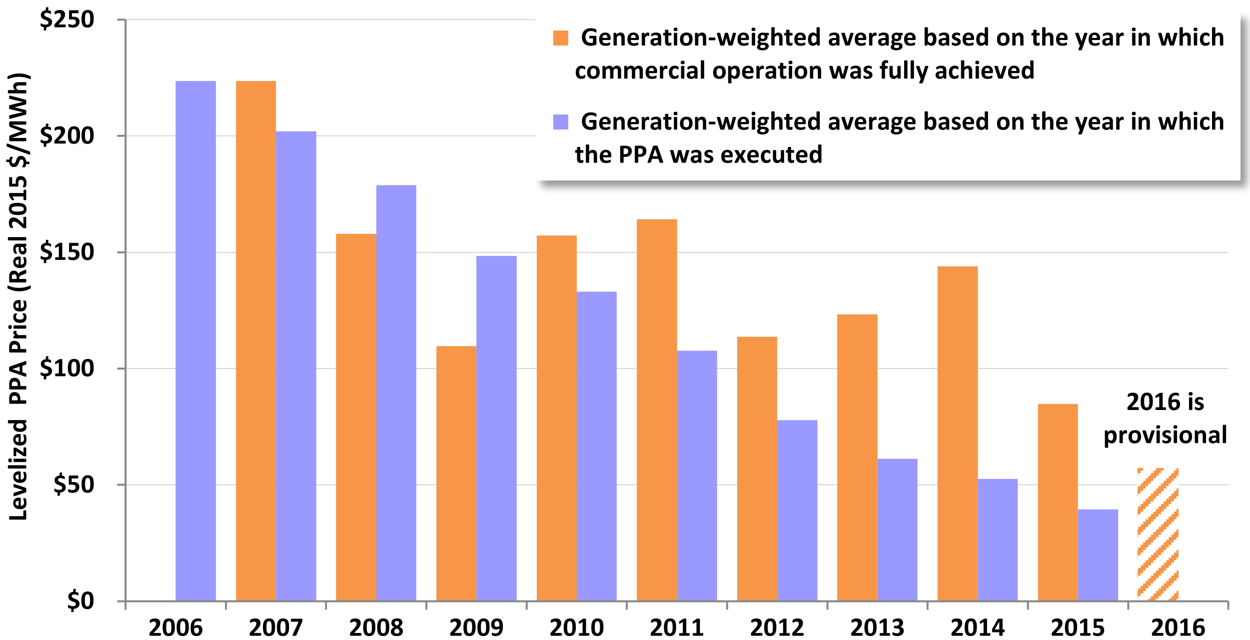


Figure 21. Average Levelized PV PPA Prices by Contract and COD Vintage

Solar's largely non-escalating and stable pricing can provide hedge value

Nearly 70% of the contracts (and MW) in the PPA 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 22 illustrates this decline by plotting over time, in real 2015 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts). In other words, for each contract vintage, Figure 22 shows the stream of generation-weighted average PPA prices over time (these are the future PPA price streams that were levelized to yield the blue-shaded columns in Figures 20 and 21).

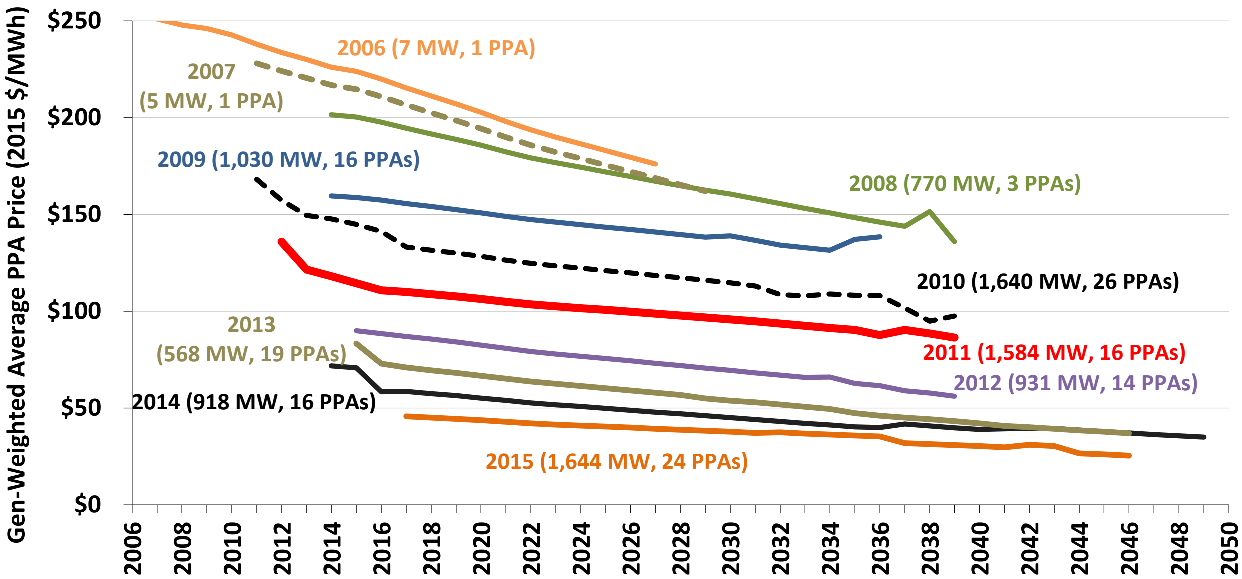


Figure 22. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013). Figure 23 illustrates this potential by plotting the future stream of average and median PV PPA prices from the 24 contracts in the sample that were executed in 2015 against a range of projections of *just the fuel costs* of natural gas-fired generation.[48] In this way, Figure 23 essentially compares the cost of *new* PV projects to the cost of *existing* gas-fired generation. This comparison is not perfect, however, given that existing gas-fired generators will also incur some small amount of non-fuel operating costs that are not accounted for, and may also still need to recover some portion of their initial capital costs to build the project.

As shown, both the generation-weighted average and median PPA prices start out well above the range of fuel cost projections in 2017, but decline (in real 2015 $/MWh terms) over time, entering the fuel cost range in 2020 and 2021, respectively, and eventually reaching the reference case fuel cost projection by the end of that decade (by which time the 80th percentile PPA price has also entered the fuel cost range) and largely tracking it thereafter.

[48] The national average fuel cost projections come from the EIA's *Annual Energy Outlook 2016* publication, and increase from around $3.89/MMBtu in 2017 to $5.36/MMBtu (both in 2015 dollars) in 2040 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using a flat heat rate of 7 MMBtu/MWh, which is aggressive compared to the heat rates implied by the reference case modeling output (which start at roughly 7.9 MMBtu/MWh in 2017 and gradually decline to just above 7 MMBtu/MWh by 2040).

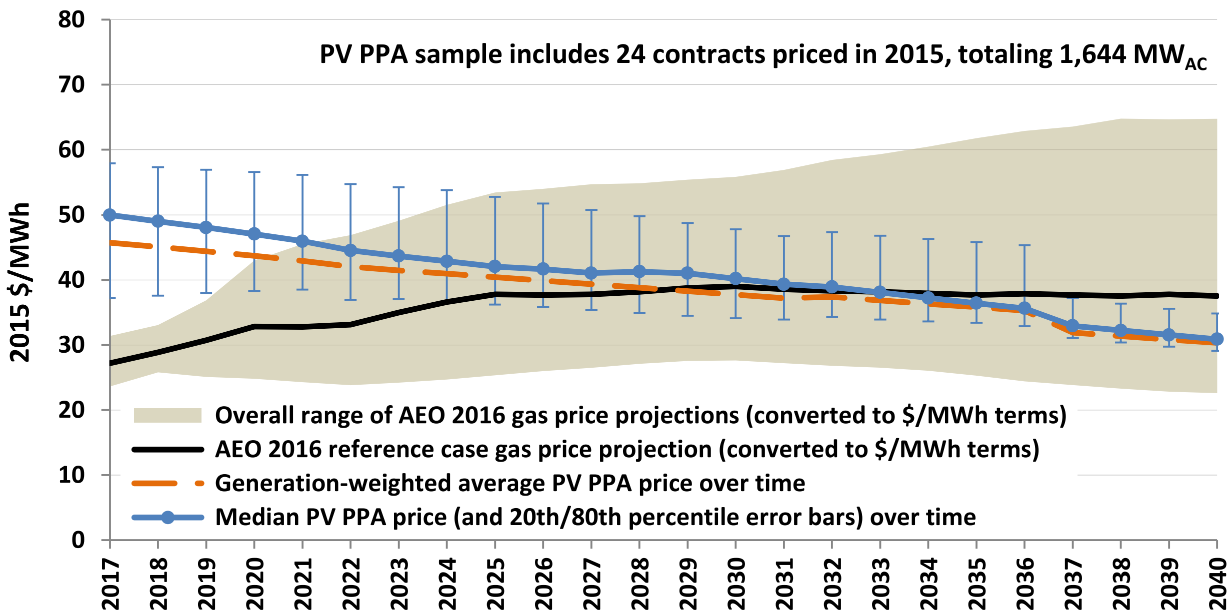


Figure 23. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

On a levelized basis (in real 2015 dollars) from 2017 through 2040, the PV PPA prices come to $42.9/MWh (median) and $40.4/MWh (generation-weighted average), compared to $34.8/MWh for the reference case fuel cost projection, suggesting that the drop in long-term gas price expectations over the past year has made it more difficult for PV to compete with *existing* gas-fired generation. That said, it is important to recognize that the PV PPA prices shown in Figure 23 have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain—actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

Moreover, as noted above, the comparison laid out in Figure 23 is not entirely apples-to-apples, as it does not include the recovery of fixed capital costs that would be incurred by *new* gas-fired generators (or other non-fuel operating costs that would be incurred by both new and existing gas-fired generators), whereas the PV PPA prices are set at a level intended to be sufficient to recover *all* costs (i.e., both initial capital costs and ongoing operating costs). By one estimate, capital and non-fuel O&M costs can add $29-$54/MWh to the levelized cost of energy from a combined-cycle gas plant (Lazard 2015).

On the other hand, Figure 23 also makes no attempt to account for the operational and environmental differences between these two generation sources, or the differences in federal and state subsidies received. In particular, it is widely known that the market value of solar declines with increased solar penetration, as a result of grid integration challenges and other characteristics related to its temporal generation profile (Mills and Wiser 2013); these factors are not considered here.

3. Utility-Scale Concentrating Solar Power (CSP)

This chapter largely follows the same format as the previous chapter, but focuses on CSP rather than PV projects.[49] Isolating these two different technologies in this way is new to this fourth edition of the report, and the split has been undertaken in an effort to simplify reporting and enable readers who are more interested in just one of these technologies to more-quickly access what they need. So as not to lose the value of being able to easily compare the two technologies when presented side by side, as they have been in previous editions, we have endeavored to include reference data points from our PV sample in many of the CSP-focused graphs in this chapter.

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1,781 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough buildout in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed a few years later by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida).

A more-concentrated burst of CSP deployment occurred in the three-year period from 2013 to 2015. In 2013, the 250 MW_{AC} Solana trough project, which includes 6 hours of molten salt storage capacity, came online in Arizona. In 2014, three additional CSP projects came fully online in California: two more trough projects (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale "solar power tower" project in the United States (Ivanpah at 377 MW_{AC}); none of these three projects includes thermal storage. A second 110 MW_{AC} solar tower project with 10 hours of built-in thermal storage—Crescent Dunes in Nevada—finished major construction activities in 2014 and became commercially operational in 2015.

In the wake of this buildout—totaling 1,237 MW_{AC}—of new CSP capacity in the past three years, there are currently no other major CSP projects moving towards construction in the United States. Moreover, two of the oldest CSP plants in the United States—SEGS I and II, which came online in the mid-1980s—have been decommissioned over the past year, following 30 years of service, and their owner has applied for permits to replace these two plants with PV. The remaining SEGS plants (III-IX) are owned by a different entity and continue to operate.

Figure 24 overlays the location of every utility-scale CSP project in the LBNL population on a map of solar resource strength in the United States, as measured by direct normal irradiance ("DNI"), which is a more appropriate measure of insolation than GHI for CSP projects.[50] With the exception of the 2010 project in Florida (75 MW_{AC}), all other CSP projects in the United

[49] One notable exception is that this chapter does not include a section on O&M prices. As noted in Section 2.3, we only have empirical O&M cost data for a single CSP project (the 75 MW_{AC} Martin trough project in Florida), and so opted to present those data along with the PV O&M cost data in Figure 13.
[50] DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position in the sky. The DNI data represent average irradiance from 1998-2009 (Perez 2012).

States have been deployed in California (1,237 MW_{AC}) and the Southwest (250 MW_{AC} in Arizona and 179 MW_{AC} in Nevada).

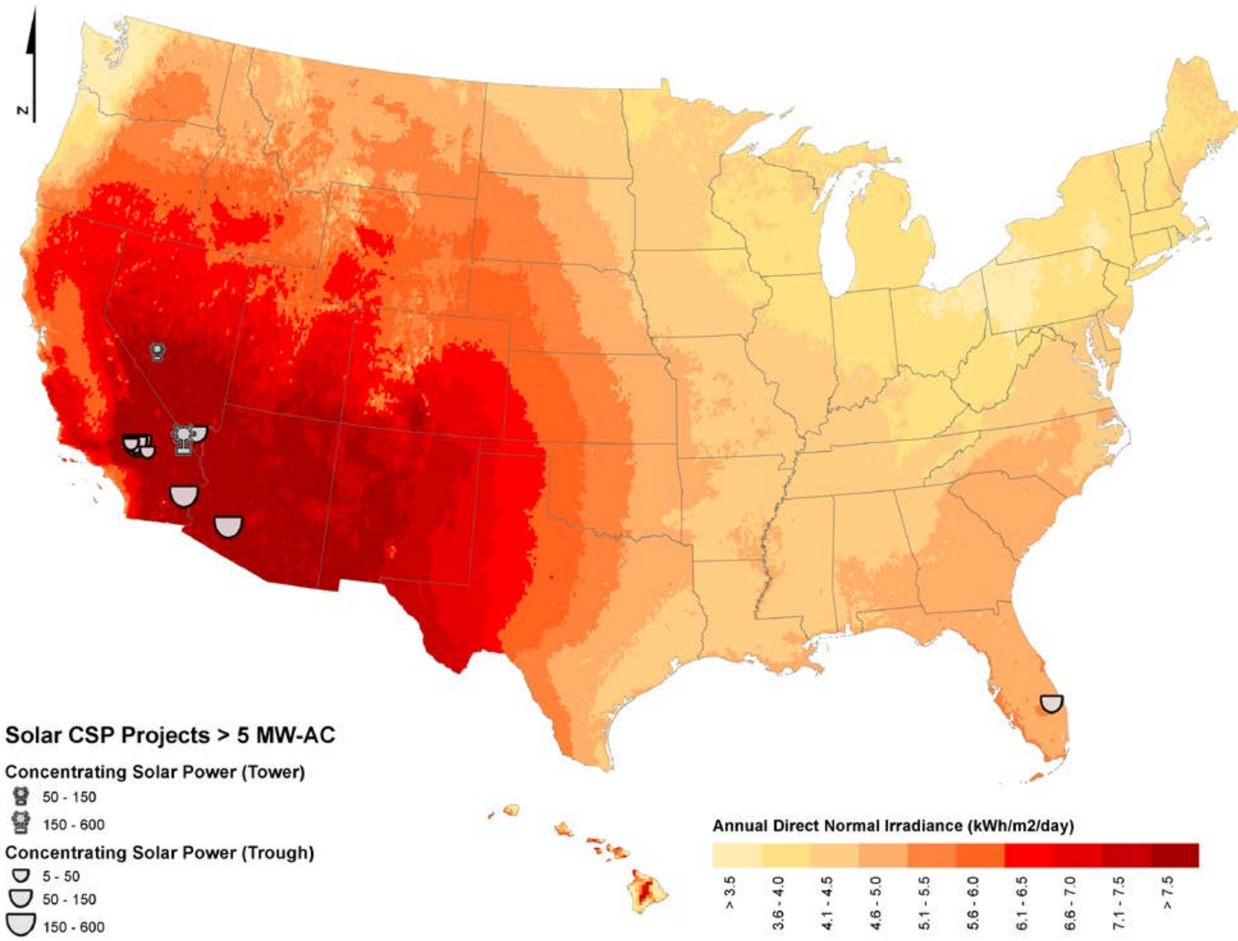


Figure 24. Map of Direct Normal Irradiance (DNI) and Utility-Scale CSP Project Locations

3.2 Installed Project Prices (7 projects, 1,381 MW_{AC})

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other CSP projects, totaling 1,381 MW_{AC}, that were commercially operational at the end of 2015 and larger than 5 MW_{AC}. Five of these seven projects feature parabolic trough technology (one of which has 6 hours of molten salt thermal storage capabilities), while the two most recently built projects use power tower technology (one project consisting of a total of 3 solar towers without long-term storage, the other just featuring one tower but with 10 hours of molten salt storage).

Figure 25 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2015),[51] and also compares their installed prices to the median installed price of PV (from Figure 7) in each year from 2010 through 2015. The small sample size makes it difficult to discern any trends. In 2014, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($\$5.17/W_{AC}$ vs. $\$6.22/W_{AC}$). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $\$6.84/W_{AC}$), while the 2014 power tower project was priced at the higher end of the range of the two trough projects built that same year. The most recent addition to our sample is the Crescent Dunes project, which faced a prolonged testing and commissioning phase that delayed commercial operation by roughly a year. The estimated cost of this project that features 10 hours of molten salt storage is the highest yet in our sample, at $\$8.86/W_{AC}$.

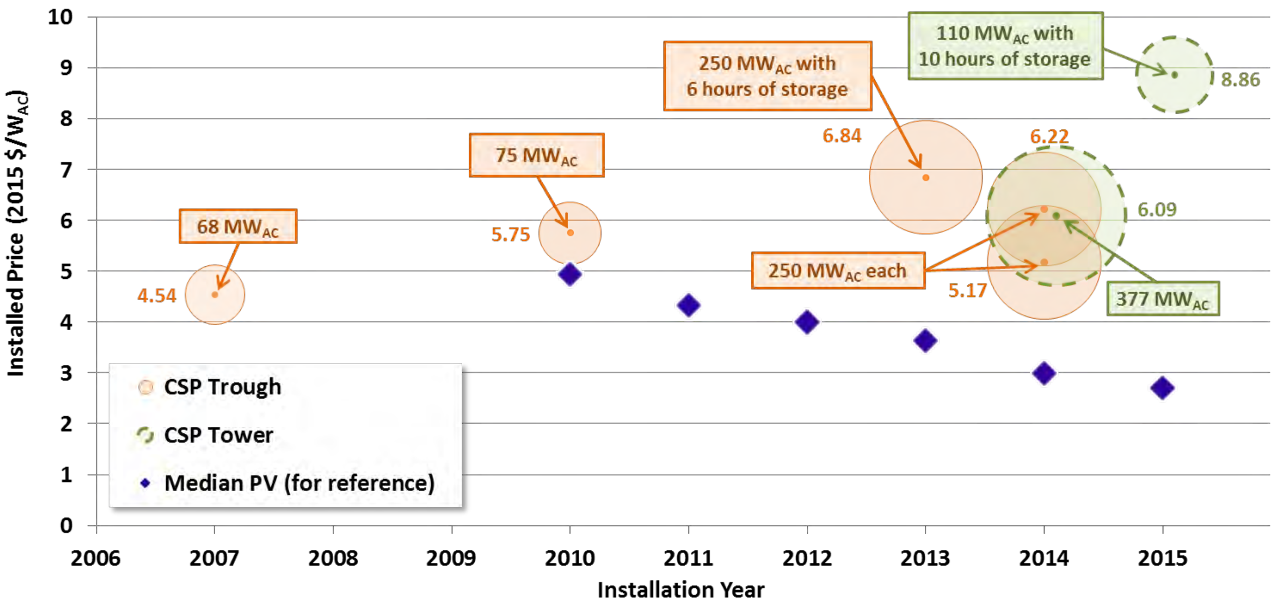


Figure 25. Installed Price of CSP Projects by Technology and Installation Year

In other words, CSP prices do not seem to have declined over time, which stands in stark contrast to the median PV prices included in the figure. Of course, the CSP sample is small, and features several different technologies and storage capabilities, which complicates comparisons.

[51] The installed CSP prices shown in Figure 25 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

3.3 Capacity Factors (14 projects, 1,588 MW_{AC})

Figure 26 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 26[52]) of our CSP project sample. The nine SEGS projects are grouped within the green and red shaded areas as indicated, rather than broken out individually. For comparison purposes, the average capacity factor in each calendar year from our sample of PV projects located in California, Nevada, and Arizona—i.e., the three states in which the CSP projects in our sample reside—are also shown.

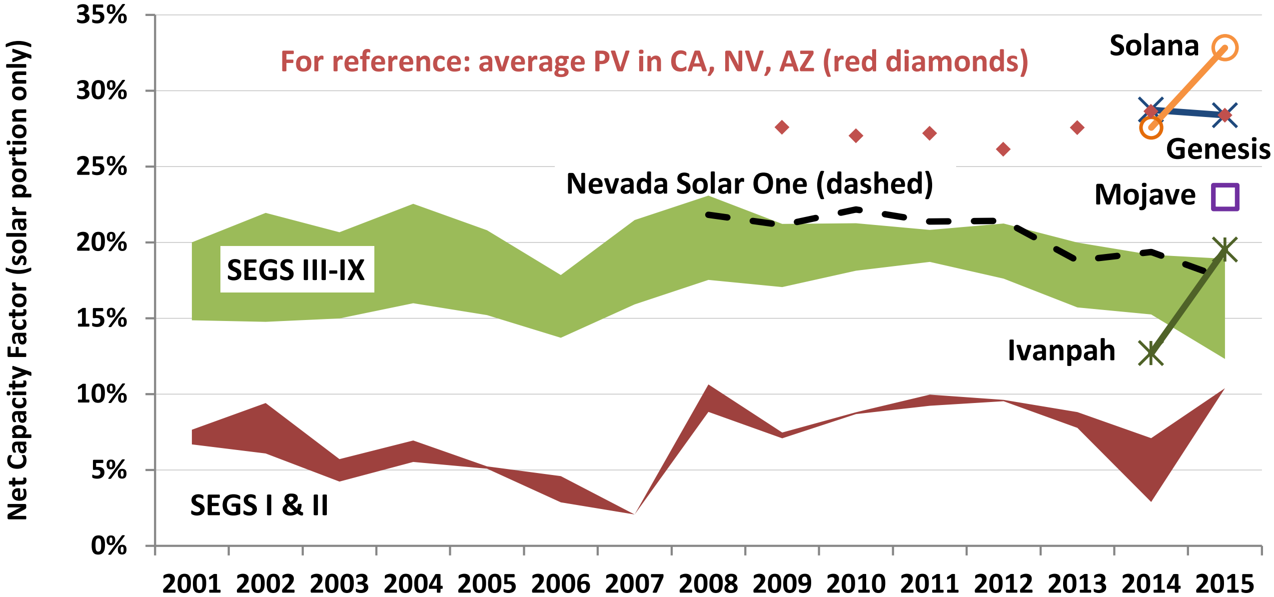


Figure 26. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

A few points are worth highlighting:

- Capacity factors at both Solana (trough with storage) and Ivanpah (power tower with no storage) improved significantly in 2015, to 32.8% and 19.5%, respectively. However, these second-year numbers are still below long-term expectations of 41% and 27%, respectively, and are expected to continue to improve in future years as these projects overcome typical start-up challenges and are fine-tuned for optimal performance (Danko 2015; Stern 2015).[53]

[52] Many 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 17.6% solar-only to 18.0% gas-included in 2015), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 200-300 basis points in 2015, depending on the project. The Ivanpah power tower project also burns gas primarily to keep its steam turbines sufficiently warm overnight and to generate the morning's first steam, both of which significantly shorten each day's ramp-up period; the amount of total generation attributable to burning gas at Ivanpah is limited to 5%, and has reportedly been under that threshold to date (Kraemer 2016).

[53] Ivanpah documentation suggests that this initial ramp-up could last as long as four years (Danko 2015). Throughout this section, long-term, steady-state capacity factor expectations are drawn from either the sources cited, or in some cases from documentation surrounding DOE loan guarantees that were provided to several CSP projects.

That said, on May 19, 2016, misaligned heliostats caused a portion of Ivanpah's Unit 3 tower to catch on fire, requiring roughly one-third of the plant's capacity to come offline. Although repairs were not expected to take long (a matter of weeks rather than months), Unit 3 had not yet returned to service at the time of writing. However brief it may be, this unplanned outage will make it more difficult for Ivanpah to comply with the terms of forbearance agreements that one of the plant's offtakers, Pacific Gas & Electric, provided in early 2016; these agreements gave Ivanpah up to an additional year to reach minimum performance levels required in the PPAs.

- Genesis (250 MW_{AC} trough with no storage) essentially maintained its 2014 capacity factor into 2015 (at 28.4%, right on expectations), while the slightly newer but otherwise very similar Mojave project (also a 250 MW_{AC} trough with no storage) posted a 2015 capacity factor of 23.0% (below expectations of 28%).
- Both of these newer trough projects, however, performed significantly better in 2015 than the existing fleet of nine older trough projects in the sample, including the eight SEGS plants (totaling 362 MW_{AC}, excluding the 30 MW_{AC} SEGS II project that was decommissioned in 2014) that have been operating in California for more than twenty years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[54] Nearly all of these projects have experienced lower solar-only capacity factors since 2012 (i.e., from 2013-2015). This decline is potentially attributable in part to inter-year variations in the solar resource, which was reportedly below average in California and the Southwest (where these projects are located) during the past three summers (3Tier 2013; Vaisala 2014; Vaisala 2015; Vaisala 2016).
- With the exception of the Solana and Genesis projects, all other CSP projects have had capacity factors that fall below that of the average PV project across California, Nevada, and Arizona. Genesis essentially matched the average PV capacity factor in both 2014 and 2015, while Solana—which has 6 hours of storage capability—exceeded the PV average by more than 4 percentage points in 2015.

Looking ahead, the 110 MW Crescent Dunes project in Nevada (with 10 hours of storage) was placed in service in late 2015 after a prolonged commissioning process, and so will enter our sample in next year's edition of this report. Additionally, several of the newer projects that have been gradually ironing out teething issues under a long-term ramp-up schedule should continue to mature over the next few years (Ivanpah's May 2016 fire notwithstanding).

[54] One additional parabolic trough project—the 75 MW_{AC} Martin project in Florida—is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1,301 MW_{AC})

The PPA price sample for CSP projects includes six of the seven projects built since the turn of the century (the 75 MW_{AC} Martin trough project in Florida, which was built in 2010, is owned by a utility, and so does not have a PPA). Contract terms range from 20 to 30 years, with both a median and mean term of 25 years.

PPA prices from five of these six projects are shown in Figure 27 (along with the de-emphasized PV PPA price sample, for reference). The sixth, Nevada Solar One, is excluded because its PPA was executed in late-2002 (and later amended in 2005), which is off the scale of the x-axis; its levelized PPA price of ~\$190/MWh (in real 2015 dollars) is the highest in our sample, though not by much.

Although most of these CSP contracts appear to have been competitive with PV at the time they were executed, PPA prices from utility-scale PV projects have since declined significantly, and CSP has not been able to keep pace. As a result, there have been no new CSP PPAs executed in the United States since 2011, and a number of previously-executed CSP contracts have been either canceled or converted to PV technology.

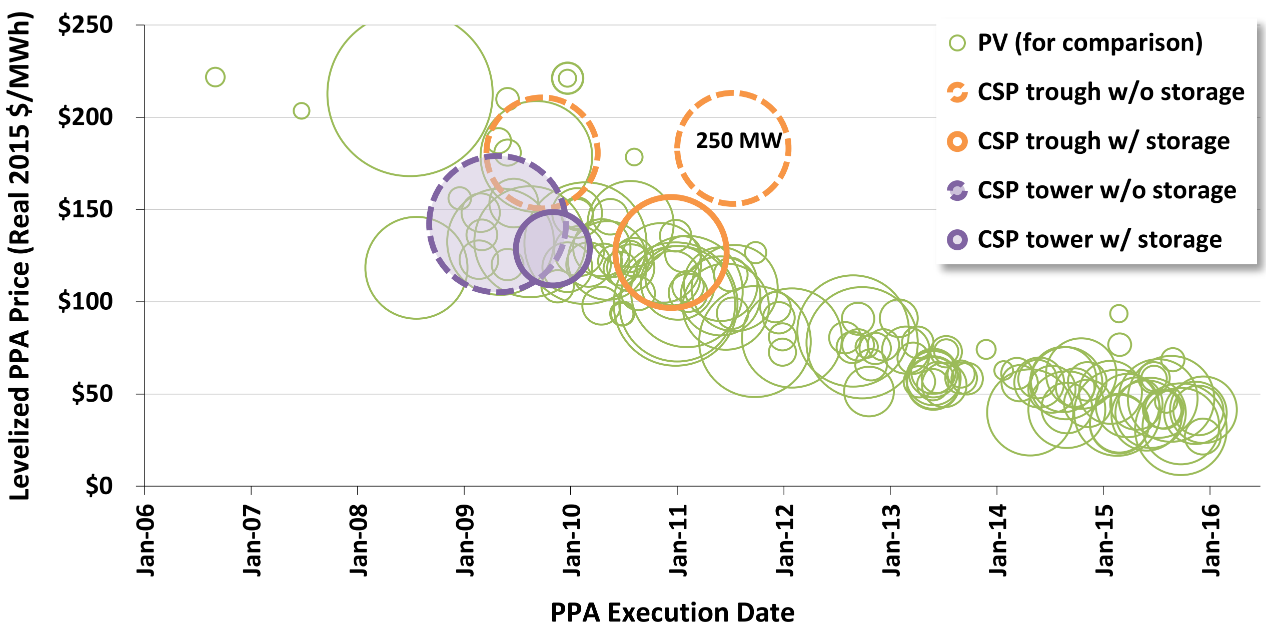


Figure 27. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

4. Conclusions and Future Outlook

This fourth edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since 2007-2009, relatively modest O&M costs, solid performance with improving capacity factors, and record-low PPA prices of around $30/MWh (levelized, in real 2015 dollars) in a few cases and under $50/MWh on average—even in areas outside of the traditional strongholds of California and the Southwest. Meanwhile, the other principal utility-scale solar technology, CSP, has also made strides in recent years—e.g., deploying several large projects featuring new trough and power tower technologies and demonstrating thermal storage capabilities—but is finding it difficult to compete in the United States with increasingly low-cost PV.[55]

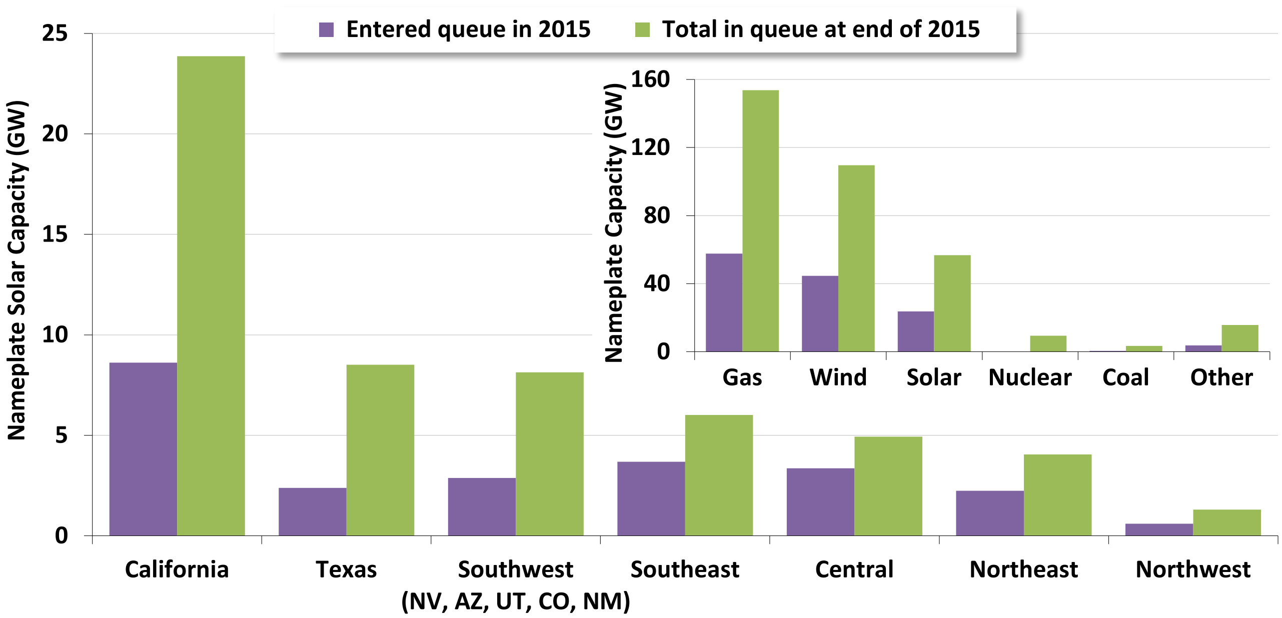
Looking ahead, December 2015's long-term extension of the 30% ITC through 2019 (along with the switch to a "start construction" rather than "placed in service" deadline), with a gradual phase down to 10% thereafter, should ensure continued momentum for the foreseeable future. Data on the amount of utility-scale solar capacity in the development pipeline support this view, and also suggest a significant expansion of the industry—both in terms of volume and geographic distribution—in the coming years. For example, Figure 28 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2015.[56] Although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built[57]—as a result, these data should be interpreted with caution. That said, efforts have been made by the FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have, in previous years, clogged these queues, and despite its inherent imperfections, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development.

[55] Avian mortality has also emerged as an unexpected potential challenge to power tower technology in particular, but also to large PV projects that, from a distance, can reportedly resemble bodies of water and attract migrating waterfowl that are injured or killed while attempting to land in the solar field.

[56] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 86% of the U.S. total. Figure 28 only includes projects that were active in the queue at the end of 2015 but that had not yet been built; suspended projects are not included.

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

At the end of 2015, there were 56.8 GW of solar power capacity (of any type—e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report—***more than five times the installed utility-scale solar power capacity in our entire project population at that time.*** These 56.8 GW (23.8 GW of which first entered the queues in 2015) represented 16% of all generating capacity within these selected queues at the time, in third place behind natural gas at 44% and wind at 31% (see Figure 28 inset). The end-of-2015 solar total is also more than 12 GW higher than the 44.6 GW of solar that were in the queues at the end of 2014, suggesting that the solar pipeline has been more than replenished over the past year, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2015.



Source: Exeter Associates review of interconnection queue data

Figure 28. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 28 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides. Perhaps not surprisingly (given the map of solar resource and PV project location shown in Figure 3 earlier), 56% of the total solar capacity in the queues at the end of 2015 is within California (42%) and the Southwest region (14%). This combined 56% is down from 60% at the end of 2014 (and 80% at the end of 2013), however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest.

For example, Figure 29 shows how the amount of solar in these queues has changed overall and by region over the last three years, from 2013-2015. With the queues in California and the Southwest rather stagnant over this period, the strong growth in the aggregate amount of solar within all queues—from 39.5 GW at the end of 2013 to 56.8 GW at the end of 2015—has come primarily from the up-and-coming Texas, Southeast, Central, and Northeast regions.

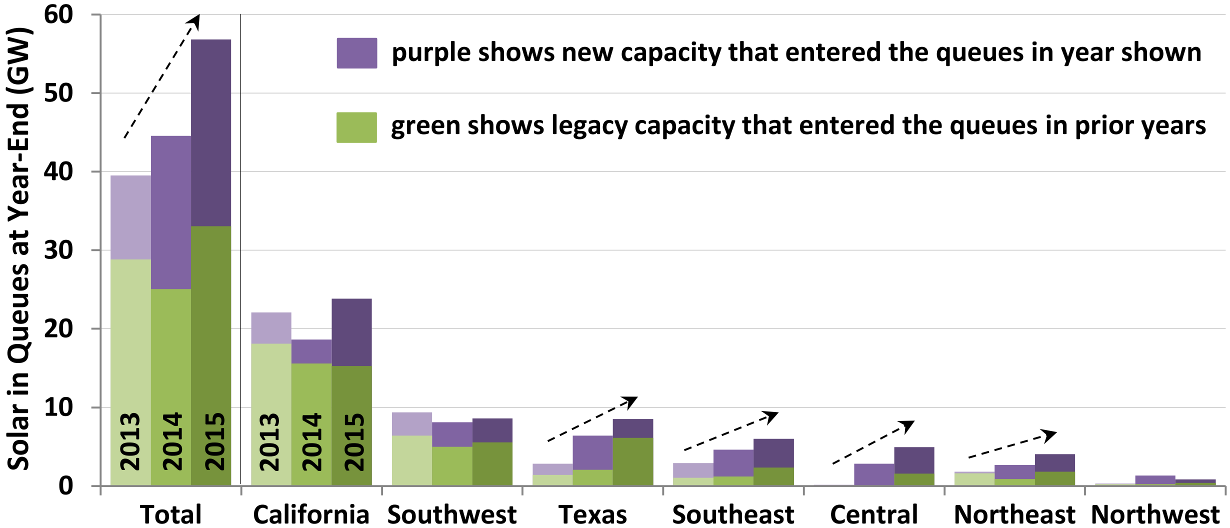


Figure 29. Solar Capacity in 35 Selected Interconnection Queues over Time

Though not all of the 56.8 GW of planned solar projects represented in Figure 29 will ultimately be built, as shown earlier in Figure 1, analysts expect nearly 12 GW to come online in 2016 alone, with many additional years of strong growth thereafter, driven in part by the long-term extension of the 30% ITC, coupled with utility-scale PV's declining costs. Of course, accompanying all of this new solar capacity will be substantial amounts of new cost, price, and performance data, which we hope to collect and analyze in future editions of this report.

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Data Sources

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

Technology Trends: Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), interviews with project developers and owners, trade press articles

Installed Prices: 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, interviews with developers and owners, trade press articles, and data previously gathered by NREL

O&M Costs: FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors: FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices: 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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Appendix

Total PV Population

State	Size Range (MW_{AC})	Year Range	2015 Sample		Total Population	
			No. of Projects	Total MW_{AC}	No. of Projects	Total MW_{AC}
AZ	5 - 290	2011 - 2015	4	122	30	1,110
AR	13 - 13	2015 - 2015	1	13	1	13
CA	6 - 586	2009 - 2015	35	1,332	107	5,047
CO	5 - 52	2007 - 2015	1	52	6	144
DE	10 - 12	2011 - 2012	-	-	2	22
FL	6 - 25	2009 - 2015	1	6	5	59
GA	6 - 81	2013 - 2015	6	177	9	230
HI	6 - 12	2012 - 2015	1	12	3	30
IL	8 - 20	2010 - 2012	-	-	2	28
IN	8 - 10	2013 - 2015	1	10	7	66
MD	6 - 20	2012 - 2015	1	9	4	48
MA	6 - 14	2014 - 2014	-	-	2	20
NV	10 - 255	2007 - 2015	4	349	14	673
NJ	5 - 18	2010 - 2015	4	41	21	189
NM	5 - 52	2010 - 2015	4	40	22	274
NY	32 - 32	2011 - 2011	-	-	1	32
NC	12 - 81	2010 - 2015	15	401	22	530
OH	8 - 10	2010 - 2011	-	-	2	18
PA	10 - 10	2012 - 2012	-	-	1	10
TN	8 - 16	2012 - 2014	-	-	3	39
TX	6 - 95	2010 - 2015	3	130	12	305
UT	50 - 80	2015 - 2015	2	130	2	130
Total	**5 - 586**	**2007 - 2015**	**83**	**2,824**	**278**	**9,016**

Total CSP Population

State	Size Range (MW_{AC})	Year Range	2015 Sample		Total Population	
			No. of Projects	Total MW_{AC}	No. of Projects	Total MW_{AC}
AZ	250	2013	-	-	1	250
CA	34 - 377	1986 - 2014	-	-	10	1,234
FL	75	2010	-	-	1	75
NV	69 - 110	2007 - 2015	1	110	2	179
Total	**34 - 377**	**1986 - 2015**	**1**	**110**	**14**	**1,737**

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2015

WIND TECHNOLOGIES MARKET REPORT

August 2016

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

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2015 Wind Technologies Market Report

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Table of Contents

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Acronyms and Abbreviations

AWEA	American Wind Energy Association
Bloomberg NEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
BOEM	Bureau of Ocean Energy Management
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EDPR	EDP Renováveis
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
HTS	Harmonized Tariff Schedule
ICE	Intercontinental Exchange
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
m^2	square meter
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement
PTC	production tax credit
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewables portfolio standard

RTO	regional transmission organization
SPP	Southwest Power Pool
USITC	U.S. International Trade Commission
W	watt
WAPA	Western Area Power Administration

Executive Summary

Annual wind power capacity additions in the United States surged in 2015 and are projected to continue at a rapid clip in the coming five years. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Wind additions are also being driven by improvements in the cost and performance of wind power technologies, yielding low power sales prices for utility, corporate, and other purchasers. At the same time, the prospects for growth beyond the current PTC cycle remain uncertain: growth could be blunted by declining federal tax support, expectations for low natural gas prices, and modest electricity demand growth.

Key findings from this year's *Wind Technologies Market Report* include:

Installation Trends

- **Wind power additions surged in 2015, with 8,598 MW of new capacity added in the United States and $14.5 billion invested.** Supported by favorable tax policy and other drivers, cumulative wind power capacity grew by 12%, bringing the total to 73,992 MW.
- **Wind power represented the largest source of U.S. electric-generating capacity additions in 2015.** Wind power constituted 41% of all U.S. generation capacity additions in 2015, up sharply from its 24% market share the year before and close to its all-time high. Over the last decade, wind power represented 31% of all U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (54%) and Great Lakes (48%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the West (22%) and Northeast (21%), and considerably less in the Southeast (2%).
- **The United States ranked second in annual wind additions in 2015, but was well behind the market leaders in wind energy penetration.** A record high amount of new wind capacity, roughly 63,000 MW, was added globally in 2015, yielding a cumulative total of 434,000 MW. The United States remained the second-leading market in terms of cumulative capacity, but was the leading country in terms of wind power production. A number of countries have achieved high levels of wind penetration; end-of-2015 wind power capacity is estimated to supply the equivalent of roughly 40% of Denmark's electricity demand, and between 20% to 30% of Portugal, Ireland, and Spain's demand. In the United States, the wind power capacity installed by the end of 2015 is estimated, in an average year, to equate to 5.6% of electricity demand.
- **Texas installed the most capacity in 2015 with 3,615 MW, while twelve states meet or exceed 10% wind energy penetration.** New utility-scale wind turbines were installed in 20 states in 2015. On a cumulative basis, Texas remained the clear leader, with 17,711 MW. Notably, the wind power capacity installed in Iowa and South Dakota supplied more than 31% and 25%, respectively, of all in-state electricity generation in 2015, with Kansas close behind at nearly 24%. A total of twelve states have achieved wind penetration levels of 10% or higher.
- **The first commercial offshore turbines are expected to be commissioned in the United States in 2016 amid mixed market signals.** At the end of 2015, global offshore wind capacity stood at roughly 12 GW. In the United States, the 30 MW Block Island project off

the coast of Rhode Island will be the first plant to be commissioned, anticipated by the end of 2016. Projects in Massachusetts, New Jersey, Virginia, and Oregon, meanwhile, all experienced setbacks. Strides continued to be made in the federal arena in 2015, both through the U.S. Department of the Interior's responsibilities in issuing offshore leases, and the U.S. Department of Energy's (DOE's) funding for demonstration projects. A total of 23 offshore wind projects totaling more than 16 GW are in various stages of development in the United States.

- **Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration.** At the end of 2015, there were 110 GW of wind power capacity within the transmission interconnection queues reviewed for this report, representing 31% of all generating capacity within these queues—higher than all other generating sources except natural gas. In 2015, 45 GW of wind power capacity entered interconnection queues (the largest annual sum since 2010), compared to 58 GW of natural gas and 24 GW of solar.

Industry Trends

- **GE and Vestas captured 73% of the U.S. wind power market in 2015.** Continuing their recent dominance as the three largest turbine suppliers to the U.S., in 2015 GE captured 40% of the market, followed by Vestas (33%) and Siemens (14%). Globally, Goldwind and Vestas were the top two suppliers, followed by GE, Siemens, and Gamesa. Chinese manufacturers continued to occupy positions of prominence in the global ratings, with five of the top 10 spots; to date, however, their growth has been based almost entirely on sales in China.
- **The manufacturing supply chain continued to adjust to swings in domestic demand for wind equipment.** With growth in the U.S. market, wind sector employment reached a new high of 88,000 full-time workers at the end of 2015. Moreover, the profitability of turbine suppliers has rebounded over the last three years. Although there have been a number of recent plant closures, each of the three major turbine manufacturers serving the U.S. market has one or more domestic manufacturing facilities. Domestic nacelle assembly capability stood at roughly 10 GW in 2015, and the United States also had the capability to produce approximately 7 GW of blades and 6 GW of towers annually. Despite the significant growth in the domestic supply chain over the last decade, conflicting pressures remain, such as: an upswing in near- to medium-term expected growth, but also strong international competitive pressures and possible reduced demand over time as the PTC is phased down. As a result, though many manufacturers increased the size of their U.S. workforce in 2015, expectations for significant supply-chain expansion have become more pessimistic.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports**. The U.S. is reliant on imports of wind equipment from a wide array of countries, with the level of dependence varying by component. Domestic content is highest for nacelle assembly (>85%), towers (80-85%), and blades and hubs (50-70%), but is much lower (<20%) for most components internal to the nacelle. Exports of wind-powered generating sets from the United States rose from $16 million in 2007 to $544 million in 2014, but fell to $149 million in 2015.
- **The project finance environment remained strong in 2015.** Spurred on by the December 2014 and March 2015 single-year extensions of the PTC's construction start deadline and

IRS safe harbor guidance, respectively, the U.S. wind market raised ~$6 billion of new tax equity in 2015—the largest single-year amount on record. Debt finance increased slightly to $2.9 billion, with plenty of additional availability. Tax equity yields drifted slightly lower to just below 8% (in unlevered, after-tax terms), while the cost of term debt fell to just 4% by the end of the year—perhaps the lowest it has ever been. Looking ahead, 2016 should be another busy year, given the recent 5-year PTC extension and phase down.

- **IPPs own the vast majority of wind assets built in 2015.** Independent power producers (IPPs) own 85% of the new wind capacity installed in the United States in 2015, with the remaining assets owned by investor-owned utilities (12%) and other entities (3%). On a cumulative basis through 2015, IPPs own 83% and utilities own 15% of U.S. wind capacity, with the remaining 2% owned by entities that are neither IPPs nor utilities (e.g., towns, schools, businesses, farmers).
- **Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales gained ground.** Electric utilities continued to be the dominant off-takers of wind power in 2015, either owning (12%) or buying (48%) power from 60% of the new capacity installed last year. Merchant/quasi-merchant projects accounted for another 29%, while direct retail purchasers – including corporate off-takers – are buying the remaining 10% (a share that should increase next year). On a cumulative basis, utilities own (15%) or buy (53%) power from 68% of all wind capacity in the United States, with merchant/quasi-merchant projects accounting for 24%, power marketers 6%, and direct retail buyers just 2% (though likely to increase in the coming years).

Technology Trends

- **Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term.** The average nameplate capacity of newly installed wind turbines in the United States in 2015 was 2.0 MW, up 180% since 1998–1999. The average hub height in 2015 was 82.0 meters, up 47% since 1998-1999, while the average rotor diameter was 102 meters, up 113% since 1998–1999.
- **Growth in rotor diameter has outpaced growth in nameplate capacity and hub height in recent years.** Rotor scaling has been especially significant in recent years, and more so than increases in nameplate capacity and hub heights, both of which have seen a stabilization of the long-term trend since at least 2011. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; by 2015, 86% of new installed wind capacity featured rotor diameters of at least 100 meters.
- **Turbines originally designed for lower wind speed sites have rapidly gained market share.** With growth in average swept rotor area outpacing growth in average nameplate capacity, there has been a decline in the average “specific power” [i] (in W/m^2) over time, from 394 W/m^2 among projects installed in 1998–1999 to 246 W/m^2 among projects installed in 2015. In general, turbines with low specific power were originally designed for lower wind speed sites. Another indication of the increasing prevalence of lower wind speed turbines is that, in 2015, the vast majority of new installations used IEC Class 3 and Class 2/3 turbines.

[i] A wind turbine’s specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

- **Turbines originally designed for lower wind speeds are now regularly employed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast.** Low specific power and IEC Class 3 and 2/3 turbines are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites. In parts of the Interior region, in particular, relatively low wind turbulence has allowed turbines designed for lower wind speeds to be deployed across a wide range of site-specific resource conditions. The tallest towers, meanwhile, have principally been deployed in the Great Lakes and Northeastern regions, in lower wind speed sites, with specific location decisions likely driven by the wind shear of the site.

Performance Trends

- **Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability.** Wind project capacity factors have generally increased over time. For a large sample of projects built from 1998 through 2014, capacity factors averaged 32.8% between 2011 and 2015 versus 31.8% between 2006 and 2010 versus 30.3% between 2000 and 2005. That being said, time-varying influences—such as inter-year variations in the strength of the wind resource or changes in the amount of wind energy curtailment—have partially masked the positive influence of turbine scaling on capacity factors. For example, wind speeds throughout the interior and western U.S. were significantly below normal for much of 2015, which negatively impacted fleet-wide capacity factors. Positively, the degree of wind curtailment has declined recently in what historically have been the most problematic areas. For example, only 1.0% of all wind generation within ERCOT was curtailed in 2015, down sharply from the peak of 17% in 2009.
- **The impact of technology trends on capacity factor becomes more apparent when parsed by project vintage.** Focusing only on performance in 2015 (to partially control for time-varying influences) and parsing capacity factors by project vintage tells a more interesting story, wherein rotor scaling over the past few years has clearly begun to drive capacity factors higher. The average 2015 capacity factor among projects built in 2014 reached 41.2%, compared to an average of 31.2% among projects built from 2004–2011 and just 25.8% among projects built from 1998–2003. The ongoing decline in specific power has been offset to some degree by a trend—especially from 2009 to 2012—towards building projects at lower-quality wind sites. Controlling for these two competing influences confirms this offsetting effect and shows that turbine design changes are driving capacity factors significantly higher over time among projects located within given wind resource regimes. Performance degradation over time is a final driver examined in this section: though many caveats are in order, older wind projects appear to suffer from performance degradation, particularly as they approach and enter their second decade of operations.
- **Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology.** Based on a sub-sample of wind projects built in 2014, average capacity factors in 2015 were the highest in the Interior region (42.7%). Not surprisingly, the regional rankings are roughly consistent with the relative quality of the wind resource in each region, and they reflect the degree to which each region has adopted turbines with lower specific power or taller towers. For example, the Great Lakes has thus far adopted these new designs to a much larger extent than has the West, with corresponding implications for average capacity factors in each region.

Cost Trends

- **Wind turbine prices remained well below levels seen several years ago.** After hitting a low of roughly $750/kW from 2000 to 2002, average turbine prices increased to more than $1,500/kW by the end of 2008. Wind turbine prices have since dropped substantially, despite increases in hub heights and especially rotor diameters. Recently announced transactions feature pricing in the $850–$1,250/kW range. These price reductions, coupled with improved turbine technology, have exerted downward pressure on project costs and wind power prices.
- **Lower turbine prices have driven reductions in reported installed project costs.** The capacity-weighted average installed project cost within our 2015 sample stood at roughly $1,690/kW—down $640/kW from the apparent peak in average reported costs in 2009 and 2010. Early indications from a preliminary sample of projects currently under construction and anticipating completion in 2016 suggest no material change in installed costs in 2016.
- **Installed costs differed by project size, turbine size, and region.** Installed project costs exhibit some economies of scale, at least at the lower end of the project and turbine size range. Additionally, among projects built in 2015, the windy Interior region of the country was the lowest-cost region, with a capacity-weighted average cost of $1,640/kW.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, it appears that projects installed over the past decade have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first several years of operation, and that O&M costs increase as projects age.

Wind Power Price Trends

- **Wind PPA prices remain very low.** After topping out at nearly $70/MWh for PPAs executed in 2009, the national average level-through price of wind PPAs within the Berkeley Lab sample has dropped to around the $20/MWh level, inclusive of the federal production tax credit (PTC), though this latest nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~$55/MWh among contracts executed in 2009 to ~$20/MWh today. Today's low PPA prices have been enabled by the combination of higher capacity factors, declining costs, and record-low interest rates documented elsewhere in this report.
- **The relative economic competitiveness of wind power declined in 2015 with the drop in wholesale power prices.** A sharp drop in wholesale power prices in 2015 made it somewhat harder for wind power to compete, notwithstanding the low wind energy PPA prices available to purchasers. This is particularly true in light of the continued expansion of wind development in the Interior region of the U.S., where wholesale power prices are among the lowest in the nation. That said, the price stream of wind PPAs executed in 2014-2016 compares very favorably to the EIA's latest projection of the fuel costs of gas-fired generation extending out through 2040.

Policy and Market Drivers

- **A long-term extension and phase down of federal incentives for wind projects is leading to a resurgent domestic market.** In December 2015, Congress passed a 5-year phased-down extension of the PTC. To qualify, projects must begin construction before January 1, 2020. In May 2016, the IRS issued favorable guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. In extending the PTC, Congress also included a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in increments of 20 percentage points per year for projects starting construction in 2017 (80% PTC), 2018 (60%), and 2019 (40%).
- **State policies help direct the location and amount of wind power development, but current policies cannot support continued growth at recent levels.** As of July 2016, RPS policies existed in 29 states and Washington D.C. Of all wind capacity built in the United States from 2000 through 2015, roughly 51% is delivered to load-serving entities with RPS obligations. Among just those wind projects built in 2015, however, this proportion fell to 24%. Existing RPS programs are projected to require average annual renewable energy additions of roughly 3.7 GW/year through 2030, only a portion of which will come from wind. These additions are well below the average growth rate in wind power capacity in recent years.
- **System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that wind energy integration costs are almost always below $12/MWh—and often below $5/MWh—for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. System operators and others continue to implement a range of methods to accommodate increased wind energy penetrations and reduce barriers to deployment: treating wind as dispatchable, increasing wind's capability to provide grid services, revising ancillary service market design, balancing area coordination, and new transmission investment. About 1,500 miles of transmission lines came on-line in 2015—less than in previous years. The wind industry, however, has identified 15 near-term transmission projects that—if all were completed—could carry 52 GW of additional wind capacity.

Future Outlook

With the five-year phased-down extension of the PTC, annual wind power capacity additions are projected to continue at a rapid clip for several years. Near-term additions will also be driven by improvements in the cost and performance of wind power technologies, which continue to yield very low power sales prices. Growing corporate demand for wind energy and state-level policies are expected to play important roles as well, as might utility action to proactively stay ahead of possible future environmental compliance obligations. As a result, various forecasts for the domestic market show expected capacity additions averaging more than 8,000 MW/year from 2016 to 2020. Projections for 2021 to 2023, however, show a downturn in additions as the PTC progressively delivers less value to the sector. Expectations for continued low natural gas prices, modest electricity demand growth, and lower near-term demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and competition from solar energy in certain regions of the country. At the same time, the potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and longer-term state RPS requirements. EPA's Clean Power Plan, depending on its ultimate fate, may also create new markets for wind. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse underlying potential trends, wind capacity additions—especially after 2020—remain uncertain.

1. Introduction

Annual wind power capacity additions in the United States surged in 2015 and are projected to continue at a rapid clip in the coming five years. Recent and projected near-term growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—having been extended for several years (though with a phase-down schedule, described further on pages 68-69), as well as a myriad of state-level policies. Wind additions are also being driven by improvements in the cost and performance of wind power technologies, yielding low power sales prices for utility, corporate, and other purchasers. At the same time, the prospects for growth beyond the current PTC cycle remain uncertain: growth could be blunted by declining federal tax support, expectations for low natural gas prices, and modest electricity demand growth.

This annual report—now in its tenth year—provides a detailed overview of developments and trends in the U.S. wind power market, with a particular focus on 2015. The report begins with an overview of key installation-related trends: trends in U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual states; the status of offshore wind power development; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind power industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into and exports from the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine size, hub height, rotor diameter, specific power, and IEC Class. After that, the report discusses wind power performance, cost, and pricing trends. In so doing, it describes trends in project performance, wind turbine transaction prices, installed project costs, and operations and maintenance (O&M) expenses. It also reviews the prices paid for wind power in the United States and how those prices compare to short-term wholesale electricity prices and forecasts of future natural gas prices. Next, the report examines policy and market factors impacting the domestic wind power market, including federal and state policy drivers as well as transmission and grid integration issues. The report concludes with a preview of possible near-term market developments.

This edition of the annual report updates data presented in previous editions while highlighting key trends and important new developments from 2015. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[1] The U.S. wind power sector is multifaceted, however, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on *distributed wind power*, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S. Department of Energy (DOE).[2] Additionally, because this report has an historical focus, and all

[1] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match AWEA's historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match AWEA's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.
[2] As used by the DOE, distributed wind is defined in terms of technology application based on a wind project's location relative to end use and power distribution infrastructure, rather than on technology size or project size. Distributed wind systems are connected either on the customer side of the meter (to meet the onsite load) or directly

U.S. wind power projects have been land-based, its treatment of trends in the offshore wind power sector is limited to a brief summary of recent developments.

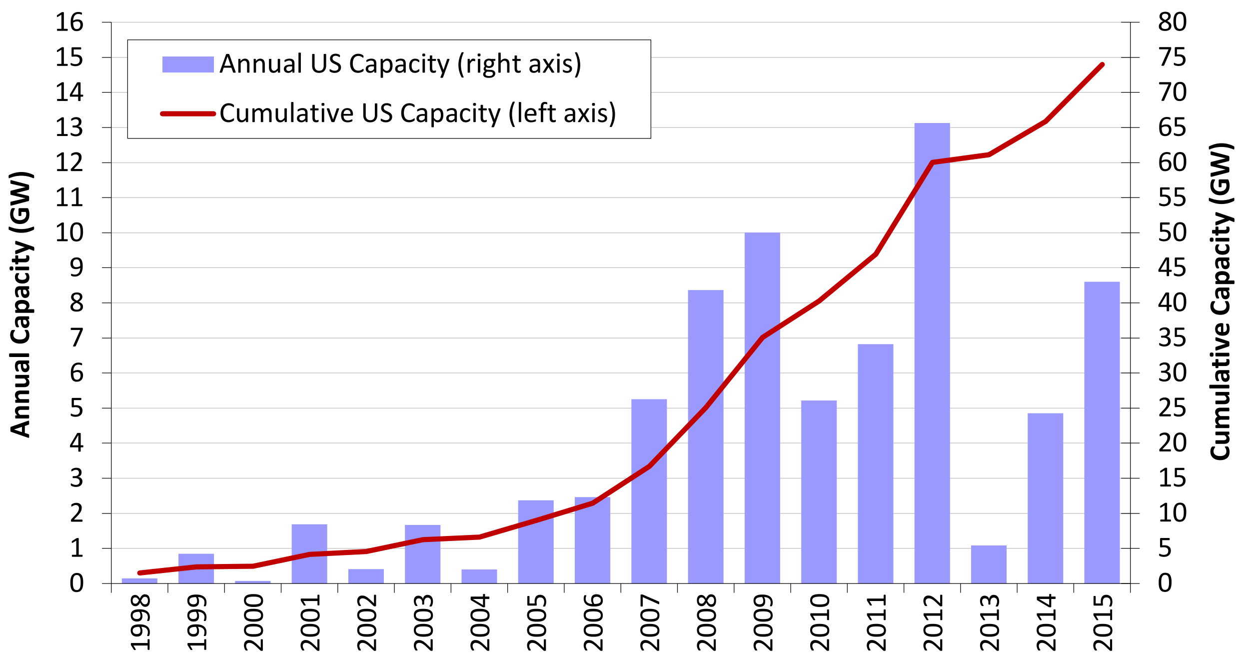
Much of the data included in this report were compiled by Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the American Wind Energy Association (AWEA), the U.S. Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). The Appendix provides a summary of the many data sources used in the report, and a list of specific references follows the Appendix. Data on wind power capacity additions in the United States (as well as wind power projects) are based largely on information provided by AWEA, although minor methodological differences may yield slightly different numbers from AWEA (2016a) in some cases. In other cases, the data shown here represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market information, with an emphasis on 2015. With some limited exceptions—including the final section of the report—the report does not seek to forecast trends.

to the local grid (to support grid operations or offset large loads nearby). For the DOE distributed wind report, see: Orrell and Foster (2016).

2. Installation Trends

Wind power additions surged in 2015, with 8,598 MW of new capacity added in the United States and $14.5 billion invested

The U.S. wind power market surged in 2015, with 8,598 MW of new capacity added, bringing the cumulative total to 73,992 MW (Figure 1).[3] This growth required $14.5 billion of investment in wind power project installations in 2015, for a cumulative investment total of more than $150 billion since the beginning of the 1980s.[45] With a record 484 MW of wind power capacity decommissioned in 2015, growth in cumulative "net" capacity in 2015 was 12%.



Source: AWEA project database

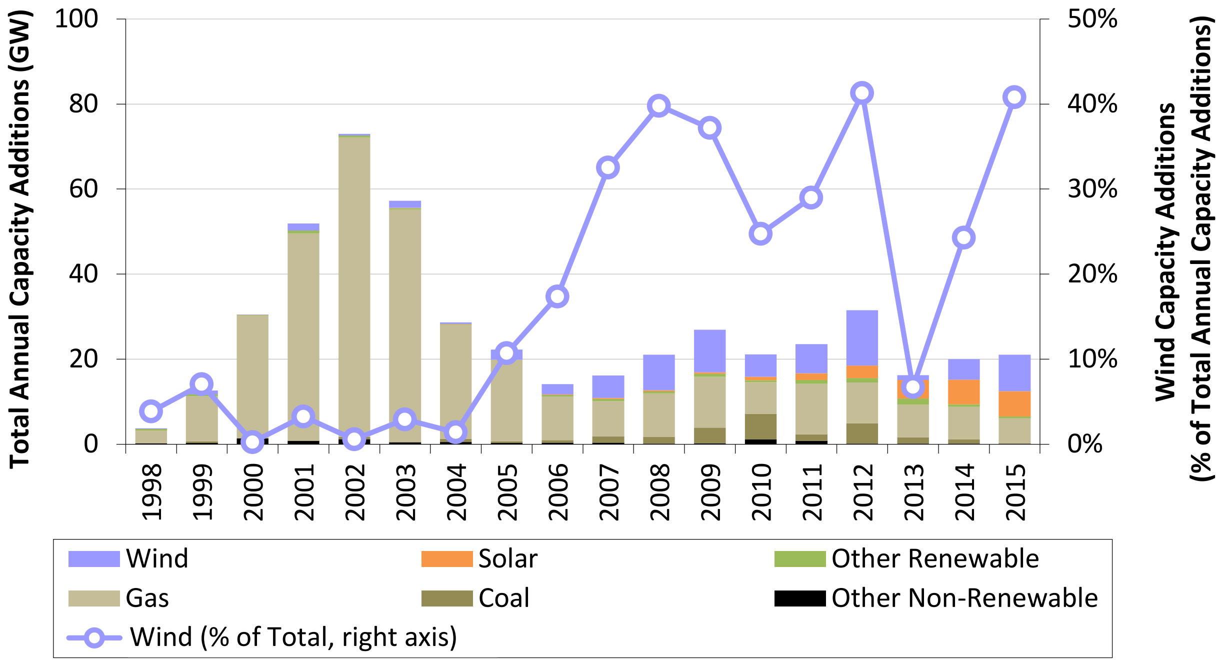
Figure 1. Annual and cumulative growth in U.S. wind power capacity

In 2015, growth was driven by recent improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand for wind power also played a role. Another key factor was the PTC, which, in December 2015, was extended for an additional 5 years—applying now to projects that begin construction before January 1, 2020, but with a progressive reduction in the value of the credit for projects starting construction after 2016. Substantial additional capacity additions are anticipated in the near term—in part due to the PTC extension.

[3] When reporting annual wind power capacity additions, this report focuses on *gross* capacity additions of large wind turbines. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning.
[4] All cost and price data are reported in real 2015$.
[5] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs.

Wind power represented the largest source of U.S. electric-generating capacity additions in 2015

Wind power has comprised a sizable share of generation capacity additions in recent years. In 2015, wind power constituted 41% of all U.S. generation capacity additions, up sharply from its 24% market share the year before and close to its all-time high (Figure 2).[6] For the second time, wind power was the largest source of annual new generating capacity, well ahead of the next two leading sources, solar power and natural gas.

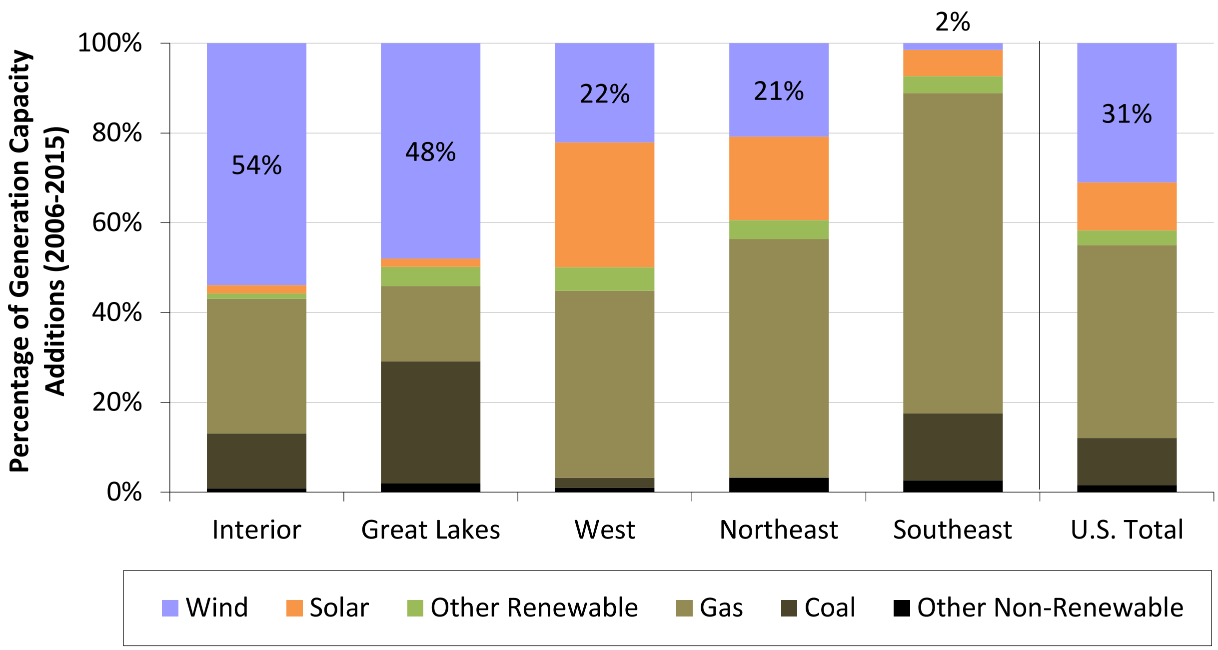


Source: ABB, AWEA, GTM Research, Berkeley Lab

Figure 2. Relative contribution of generation types in annual capacity additions

Over the last decade, wind power represented 31% of total U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (54%) and Great Lakes (48%) regions (Figure 3; see Figure 29, later, for regional definitions). Its contribution to generation capacity growth over the last decade is somewhat smaller—but still significant—in the West (22%) and Northeast (21%), and considerably less in the Southeast (2%).

[6] Data presented here are based on gross capacity additions, not considering retirements. Furthermore, they include only the 50 U.S. states, not U.S. territories.



Source: ABB, AWEA, GTM Research, Berkeley Lab

Figure 3. Generation capacity additions by region (2006–2015)

The United States ranked second in annual wind additions in 2015, but was well behind the market leaders in wind energy penetration

Global wind additions yet again reached a new high in 2015, with roughly 63,000 MW of new capacity, 23% above the previous record of 51,000 MW added in 2014. Cumulative global capacity stood at approximately 434,000 MW at the end of the year (Navigant 2016a; Table 1).[7] The United States ended 2015 with 17% of total global wind power capacity, a distant second to China by this metric (Table 1).[8] On the basis of wind power production, however, the United States remained the leading country globally in 2015 (AWEA 2016a). Annual growth in cumulative capacity in 2015 was 23% for the United States and 17% globally.

After leading the world in annual wind power capacity additions from 2005 through 2008, and then losing the mantle to China from 2009 through 2011, the United States narrowly regained the global lead in 2012. In 2013, the United States dropped precipitously to 6th place in annual additions, but then regained ground, rising to 3rd place in 2014 and 2nd place in 2015 (Table 1). The U.S. wind power market represented 14% of global installed capacity in 2015.

[7] Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from Navigant (2016a) but are updated with the U.S. data presented here. Some disagreement exists among these data sources and others.

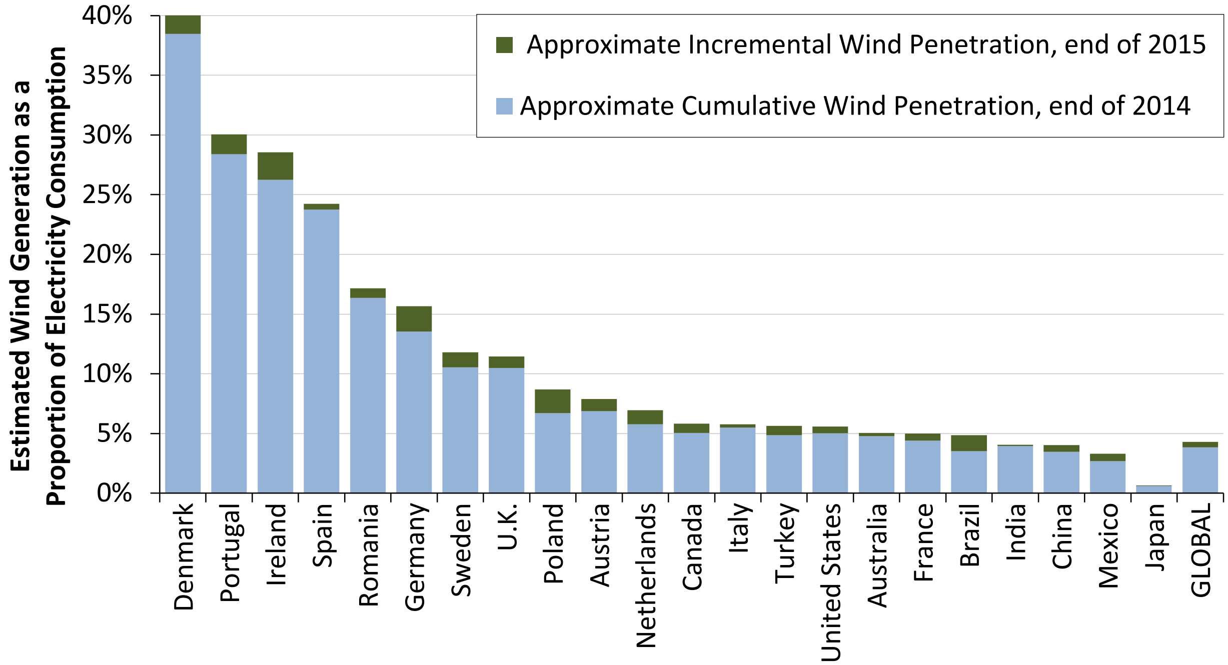
[8] Wind power additions and cumulative capacity in China include capacity that was installed but that had not yet begun to deliver electricity by the end of 2015, due to a lack of coordination between wind developers and transmission providers and the lengthier time that it takes to build transmission and interconnection facilities. All of the U.S. capacity reported here, on the other hand, was capable of electricity delivery.

Table 1. International Rankings of Wind Power Capacity

Annual Capacity (2015, MW)		Cumulative Capacity (end of 2015, MW)	
China	30,293	China	145,053
United States	**8,598**	**United States**	**73,992**
Germany	6,013	Germany	44,986
Brazil	2,754	India	25,352
India	2,623	Spain	22,665
Canada	1,506	United Kingdom	13,388
Poland	1,266	Canada	11,190
France	1,073	France	10,243
United Kingdom	975	Brazil	9,346
Turkey	956	Italy	8,851
Rest of World	7,078	*Rest of World*	68,464
TOTAL	**63,135**	**TOTAL**	**433,530**

Source: Navigant; AWEA project database for U.S. capacity

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 4 presents data on end-of-2015 (and end-of-2014) installed wind power capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors and then divided by projected 2016 (and 2015) electricity consumption. Using this approximation for the contribution of wind power to electricity consumption, and focusing only on those countries with the greatest cumulative installed wind power capacity, end-of-2015 installed wind power is estimated to supply the equivalent of roughly 40% of Denmark's electricity demand, and between 20% to 30% of Portugal, Ireland, and Spain's demand. In the United States, the cumulative wind power capacity installed at the end of 2015 is estimated, in an average year, to equate to 5.6% of the nation's electricity demand. On a global basis, wind energy's contribution is estimated to be approximately 4.3%.



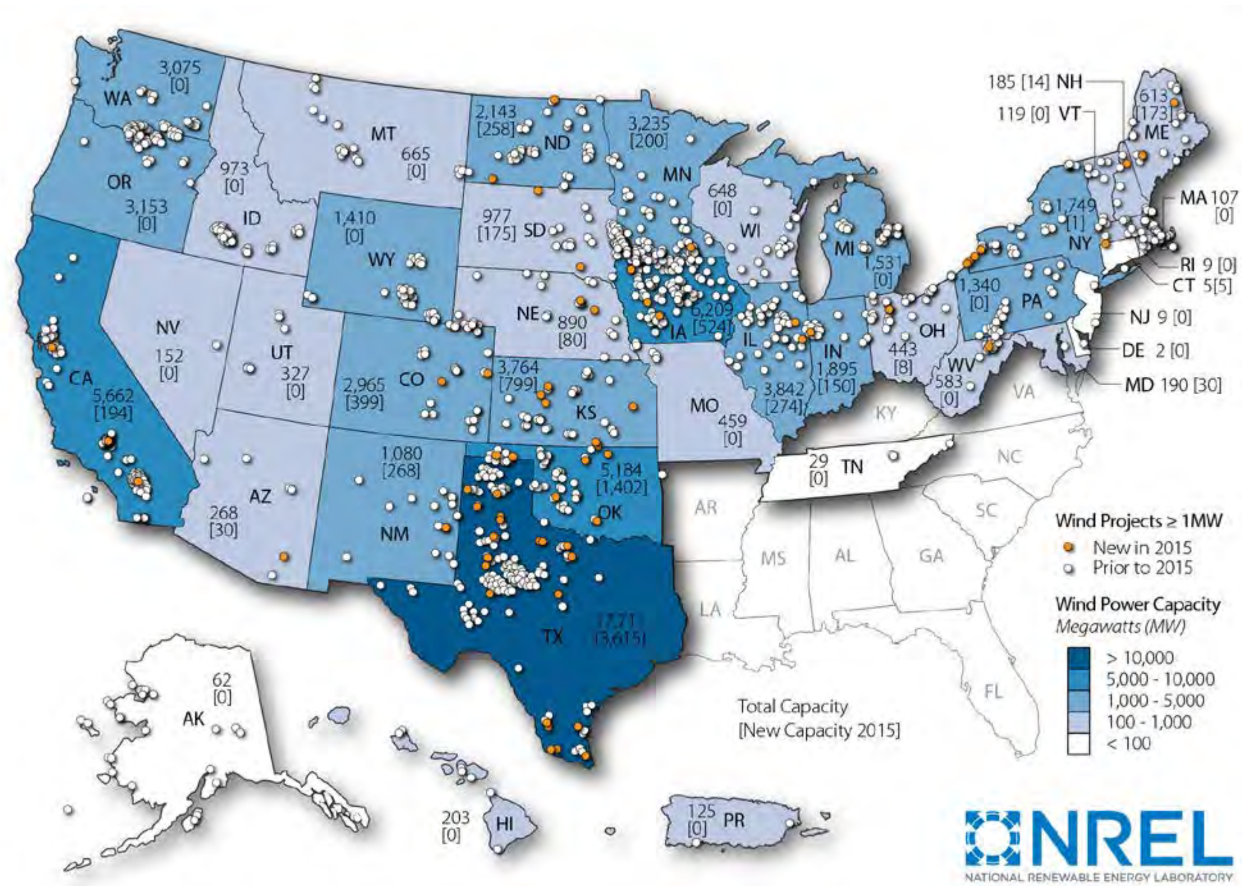
Source: Berkeley Lab estimates based on data from Navigant, EIA, and elsewhere

Figure 4. Approximate wind energy penetration in the countries with the greatest installed wind power capacity

Texas installed the most capacity in 2015 with 3,615 MW, while twelve states meet or exceed 10% wind energy penetration

New utility-scale wind turbines were installed in 20 states in 2015. Texas installed the most new wind capacity of any state, with 3,615 MW. As shown in Figure 5 and Table 2, other leading states in terms of new capacity included Oklahoma (1,402 MW), Kansas (799 MW), Iowa (524 MW), and Colorado (399 MW).

On a cumulative basis, Texas remained the clear leader among states, with 17,711 MW installed at the end of 2015—nearly three times as much as the next-highest state (Iowa, with 6,209 MW). In fact, Texas has more wind capacity than all but five countries—including the rest of the United States—worldwide. States distantly following Texas in cumulative installed capacity include Iowa, California, Oklahoma, Illinois, Kansas, Minnesota, Oregon, and Washington—all with more than 3,000 MW. Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2015, with 24 of these topping 500 MW, 17 topping 1,000 MW, and 11 topping 2,000 MW. Although all commercial wind projects in the United States to date have been installed on land, offshore development activities continued in 2015, as discussed in the next section.



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2015.

Figure 5. Location of wind power development in the United States

Some states have realized high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2015 divided by total in-state electricity generation in 2015.[9] Iowa leads the list, with 31.3% wind penetration, followed by South Dakota (25.5%) and Kansas (23.9%). A total of twelve states have achieved wind penetration levels of 10% or higher.

[9] Wind energy penetration can either be expressed as a percentage of in-state load or in-state generation. In-state generation is used here, primarily because wind energy (like other energy resources) is often sold across state lines, which tends to distort penetration levels expressed as a percentage of in-state load. Also note that by focusing on generation in 2015, Table 2 does not fully capture the impact of new wind power capacity added during 2015 (particularly if added towards the end of the year).

Table 2. U.S. Wind Power Rankings: the Top 20 States

Installed Capacity (MW)				Percentage of In-State Generation	
Annual (2015)		Cumulative (end of 2015)		Actual (2015)*	
Texas	3,615	Texas	17,711	Iowa	31.3%
Oklahoma	1,402	Iowa	6,209	South Dakota	25.5%
Kansas	799	California	5,662	Kansas	23.9%
Iowa	524	Oklahoma	5,184	Oklahoma	18.4%
Colorado	399	Illinois	3,842	North Dakota	17.7%
Illinois	274	Kansas	3,764	Minnesota	17.0%
New Mexico	268	Minnesota	3,235	Idaho	16.2%
North Dakota	258	Oregon	3,153	Vermont	15.4%
Minnesota	200	Washington	3,075	Colorado	14.2%
California	194	Colorado	2,965	Oregon	11.3%
South Dakota	175	North Dakota	2,143	Maine	10.5%
Maine	173	Indiana	1,895	Texas	10.0%
Indiana	150	New York	1,749	Nebraska	8.0%
Nebraska	80	Michigan	1,531	Wyoming	7.7%
Arizona	30	Wyoming	1,410	Montana	6.6%
Maryland	30	Pennsylvania	1,340	Washington	6.5%
New Hampshire	14	New Mexico	1,080	New Mexico	6.3%
Ohio	8	South Dakota	977	California	6.2%
Connecticut	5	Idaho	973	Hawaii	6.1%
New York	1	Nebraska	890	Illinois	5.5%
Rest of U.S.	0	*Rest of U.S.*	5,203	*Rest of U.S.*	1.0%
TOTAL	**8,598**	**TOTAL**	**73,992**	**TOTAL**	**4.7%**

* Based on 2015 wind and total generation by state from EIA's *Electric Power Monthly*.

Source: AWEA project database, EIA

The first commercial offshore turbines are expected to be commissioned in the United States in 2016 amid mixed market signals

At the end of 2015, global cumulative offshore wind power capacity stood at roughly 12,000 MW (Navigant 2016a), with Europe continuing as the primary center of activity. Navigant (2016a) reports more than 3,500 MW of new offshore wind capacity being commissioned in 2015, with more than 3,000 MW under construction at the end of 2015.[10]

The 30 MW Block Island project, developed by Deepwater Wind, began construction in 2015. All five jacket foundations were installed in 2015 and cable installation was expected to be complete by June 2016. Once installed, the project will consist of five GE Haliade 6 MW offshore wind turbines. The project is expected to be commissioned by the end of 2016, becoming the first commercial offshore wind power plant to operate in the United States.

[10] Various data sources report different figures, in part due to differing perspectives on when to consider a project "completed."

A number of other high-profile projects have run into legal and political headwinds:

- National Grid and NSTAR canceled their power purchase agreements (PPA) with the 468 MW **Cape Wind** project after it failed to meet contractual deadlines. The Bureau of Ocean Energy Management (BOEM) approved the project's application to suspend the 28-year operations term of its offshore area lease, but denied the project's request to stop its annual lease payments (Hopper 2015). The Massachusetts Energy Facilities Siting Board denied Cape Wind's request for permit extension for its electricity transmission lines in April 2016.
- New Jersey passed the Offshore Wind Economic Development Act in 2010, creating a program for offshore renewable energy credits. However, as of the end of 2015, the New Jersey Board of Public Utilities (BPU) had twice rejected the 25 MW **Fishermen's Energy Atlantic City Windfarm's** application for the state's Offshore Renewable Energy Credit program. The State Supreme Court subsequently upheld the decision of the BPU. Fishermen's Energy continues to face roadblocks; legislative efforts to allow the project to reapply for BPU approval were vetoed by the governor. In 2012, DOE selected Fishermen's Energy as one of seven demonstration projects to receive $4 million in funding, and chose it as one of three projects eligible for an additional $46.7 million in funding in 2014. That eligibility was renewed in 2016 upon evaluation of the project against established milestones.
- Dominion Virginia Power announced that it would delay the 12 MW **Virginia Offshore Wind Technology Advancement Project** (VOWTAP) after initial bids for construction came in at 63%-74% above initial estimates. A second round of bidding reduced the cost of the project to 30%-65% above the initial estimate.[11] BOEM approved a research lease for the project in March 2016. DOE chose VOWTAP as one of seven offshore projects (including Fishermen's Energy) to receive $4 million in 2012 and, in 2014, up to an additional $46.7 million in funding. However, DOE withdrew the offer in May 2016 upon evaluation of the project, determining that VOWTAP could not guarantee commissioning prior to 2020.

The high cost of offshore wind coupled with the complex regulatory environment serve as key challenges for the U.S. offshore wind industry. The mechanisms for planning, siting, and permitting offshore wind projects are fragmented, requiring developers to engage with multiple local, state, and federal agencies and stakeholders. Furthermore, regulatory processes to secure site control and construction authorization are mostly decoupled from offtake agreements that support the economics of an offshore wind project. U.S. developers with competitive lease auctions must separately negotiate PPAs, which increases uncertainty relative to European markets. Meanwhile, due to the lack of sufficient policy support to cover the high cost of offshore wind in most states, offtake agreements and financing have been hard to obtain. NREL estimates that the levelized cost of fixed-bottom offshore wind energy in 2014 was $193/MWh in the United States (Moné et al. 2015).

Despite these challenges, the United States remains interested in offshore wind project development. Key drivers include the close proximity of offshore wind resources to population centers, which could address transmission congestion, the potential for local economic development benefits, and superior capacity factors and larger potential project sizes compared to limited developable land-based wind resources in some coastal regions.

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[11] The initial projection for VOWTAP was $230 million, the first round of bidding came in at $375-400 million, and the second round of bidding came in at $300-380 million.

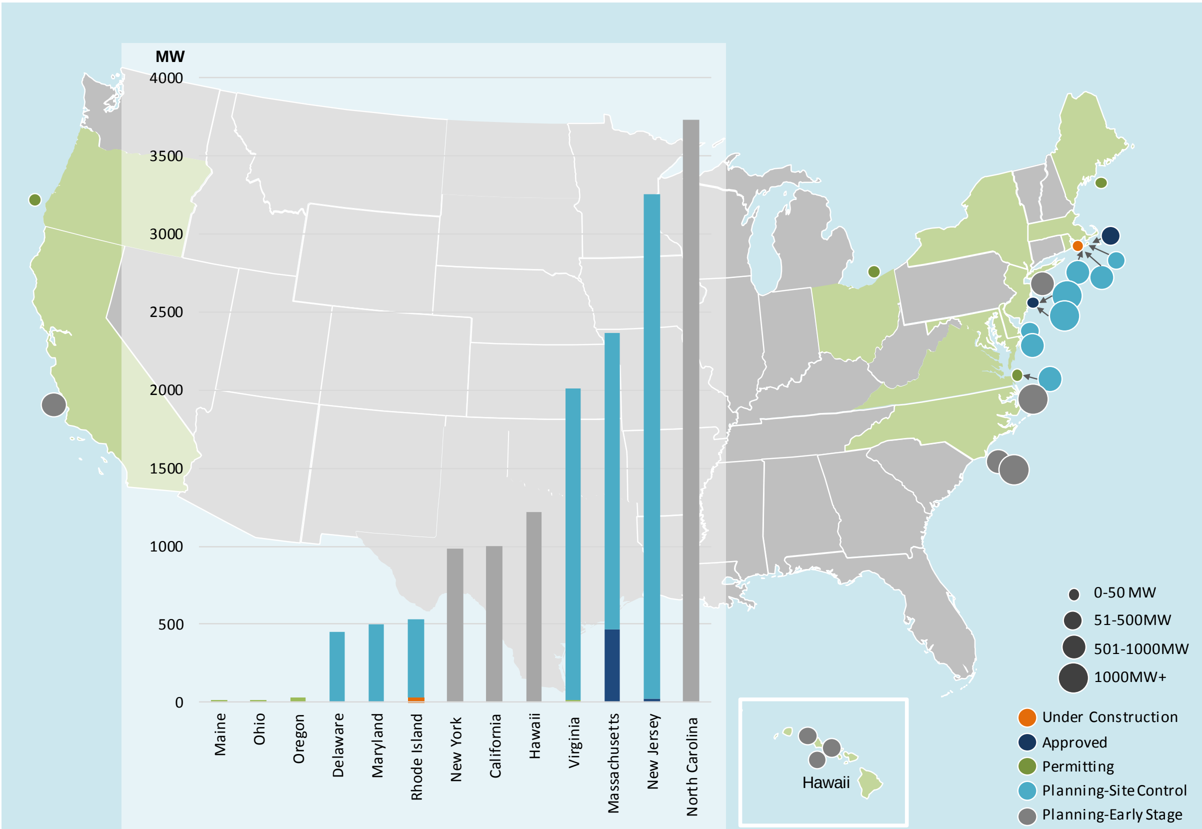
Policy support for offshore wind originates in state initiatives and policies as well as federal incentives and programs. Of those states with RPS requirements, Maryland, New Jersey, and Maine have offshore-specific carve-out mandates or goals. At the federal level, the recent extension of the PTC and ITC may help support offshore projects that are able to meet the relevant deadlines. In addition, federal support in the form of regulatory approvals and technology investment is boosting commercial interest. BOEM had granted five leases for sites in Rhode Island, Massachusetts, Maryland, and Virginia as of the end of 2015. In 2015, BOEM issued four additional leases from competitive auctions for offshore wind areas in Massachusetts and New Jersey. In January 2015, the Massachusetts auction received bids for two of the four available zones, potentially adding up to 1.4 GW of offshore development.[12] In November 2015, the New Jersey auction resulted in two lease areas totaling more than 3 GW of announced potential offshore wind power.[13] Further competitive leases are planned in New York, North Carolina, and South Carolina.

DOE has also made significant investments in offshore wind energy, including funding for advanced technology demonstration partnerships. In 2012, DOE launched the Offshore Wind Advanced Technology Demonstration program by selecting seven offshore demonstration projects to receive up to $4 million to complete engineering, design, and permitting phases of development. In 2014, DOE selected three innovative projects from the seven demonstration projects for additional federal funding of $6.7 million each to finalize the initial development phase. These three projects, Dominion Power’s VOWTAP (12 MW, Virginia), Principle Power’s WindFloat Pacific (up to 30 MW, Oregon), and Fishermen’s Energy Atlantic City Windfarm (at least 24 MW, New Jersey), also received eligibility to receive up to $40 million in funding for future phases. In addition, DOE selected two alternate projects, University of Maine’s 12 MW Aqua Ventus project in Maine and Lake Erie Energy Development Corporation’s 18 MW Icebreaker Project in Ohio, to receive $3 million each to complete the engineering designs of their technology concepts.

In May 2016, DOE decided that Principle Power’s WindFloat Pacific project in Oregon and Dominion’s VOWTAP in Virginia would no longer be eligible for the funding due to their inability to guarantee project milestones. Instead, DOE selected the two alternate projects in Maine and Ohio to receive the additional funding as part of the demonstration program.

Figure 6 identifies 23 proposed offshore wind projects in the United States in various stages of development. These projects total more than 16 GW of potential capacity, of which approximately 10 GW have obtained site control through leases or determinations of no competitive interest.[14] The proposed projects are primarily located in the Northeast and Mid-Atlantic, with one project each in the Great Lakes, Pacific Northwest, and California. Developers have also filed lease requests to BOEM for three areas in Hawaii in 2015 and 2016.

[12] The potential capacity for the two lease areas is based on announced estimated capacity by the developers, Offshore MW LLC (400 MW) and DONG Energy (1000 MW).
[13] The potential capacity of 3 GW is based on the announced capacity by DONG Energy (1000 MW) and estimates by NREL for US Wind’s lease area (2230 MW).
[14] A project reaches the site control phase when the developer obtains exclusive development rights to a site.



Note: Capacities of projects are based on owner/developer announced capacity. In cases where announced capacity is unavailable, the capacity refers to the estimated maximum potential, which assumes an average capacity density of 3 MW/ km^2 based on spacing of 9 to 10 rotor diameters developed. For methodology of estimated maximum potential, please refer to Musial et al. (2013a, 2013b). For definitions of the different stages of development, please refer to Smith et al. (2015).

Figure 6. Offshore wind power projects under development in the United States as of June 2016

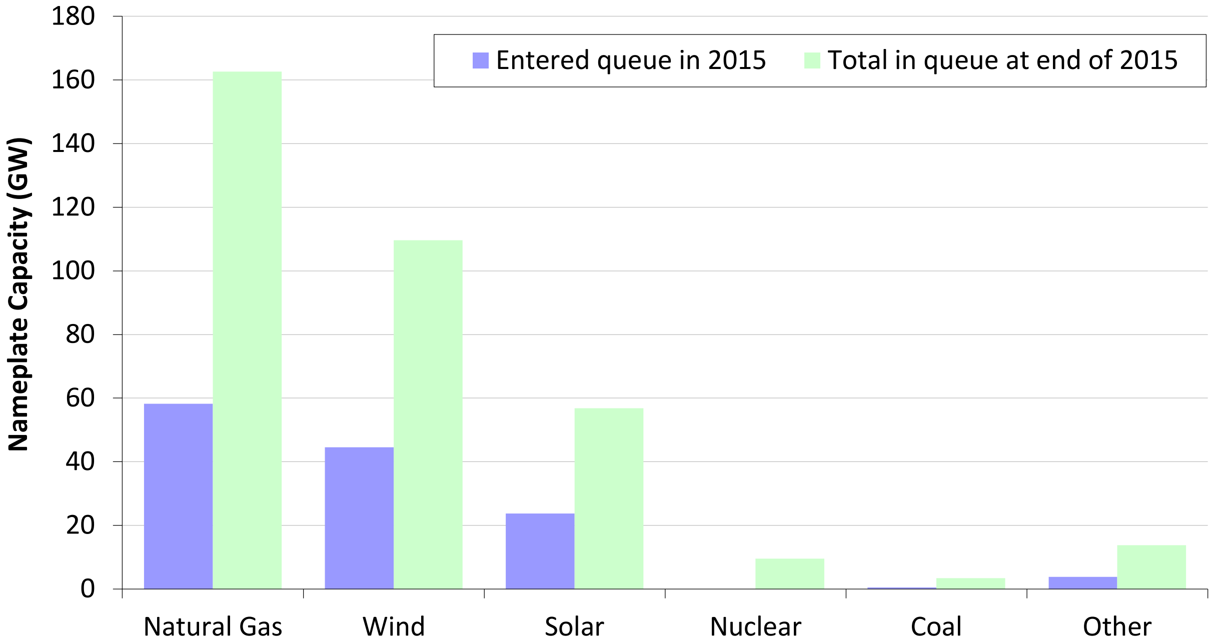
Of the projects identified in Figure 6, Deepwater Wind's Block Island project off the coast of Rhode Island is the only one that has a PPA. Achievement of this milestone enabled the project to close financing and to begin construction in spring 2015. Other projects are working with regulators to finalize design, secure permits, and/or establish power sales agreements. The recent challenges highlighted above suggest that the schedules for these projects are subject to uncertainty.

Data from interconnection queues demonstrate that a substantial amount of wind power capacity is under consideration

One testament to the continued interest in land-based wind energy is the amount of wind power capacity currently working its way through the major transmission interconnection queues across the country. Figure 7 provides this information for wind power and other resources aggregated across 34 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[15] These data should be interpreted with

[15] The queues surveyed include PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), New York ISO (NYISO), ISO-New England (ISO-NE), California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power

caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built. Efforts have been made by FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have clogged these queues in past years. One consequence of those efforts is that the total amount of wind power capacity in the nation's interconnection queues has declined dramatically since 2009.



Source: Exeter Associates review of interconnection queues

Figure 7. Generation capacity in 34 selected interconnection queues, by resource type

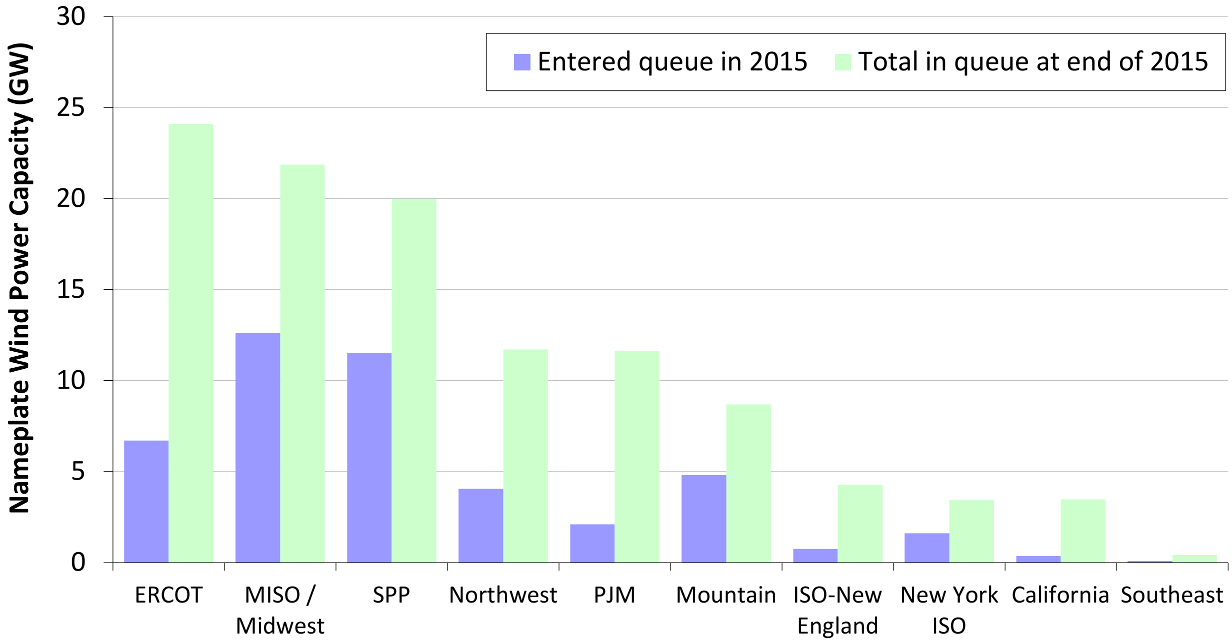
Even with this important caveat, the amount of wind capacity in the nation’s interconnection queues still provides at least some indication of the amount of planned development. At the end of 2015, there were 110 GW of wind power capacity within the interconnection queues reviewed for this report—almost one-and-a-half times the installed wind power capacity in the United States. This 110 GW is an increase from the end of 2014 (96 GW), and represented 31% of all generating capacity within these selected queues at that time, higher than all other generating sources except for natural gas. In 2015, 45 GW of wind power capacity entered the interconnection queues, compared to 58 GW of natural gas and 24 GW of solar. The 45 GW of new wind capacity entering the queues in 2015 is the largest annual sum since 2010.

Of note, however, is that the total amount of wind, coal, and nuclear power in the sampled interconnection queues (considering gross additions and project drop-outs) has generally declined in recent years, whereas natural gas and solar capacity has increased or held steady.

Administration (BPA), Tennessee Valley Authority (TVA), and 24 other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 88% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2015 but that had not yet been built; suspended projects are not included.

Since 2009, for example, the amount of wind power capacity has dropped by 64%, coal by 89%, and nuclear by 67%, whereas solar capacity has increased by 68% and natural gas by 47%.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with larger amounts in ERCOT (22%), the Midwest (20%), Southwest Power Pool (SPP) (18%), the Northwest (11%), and the PJM Interconnection (11%). Somewhat smaller amounts are found in the Mountain region (8%), ISO-New England (4%), New York ISO (3%), California (3%), and the Southeast (0.5%).



Source: Exeter Associates review of interconnection queues

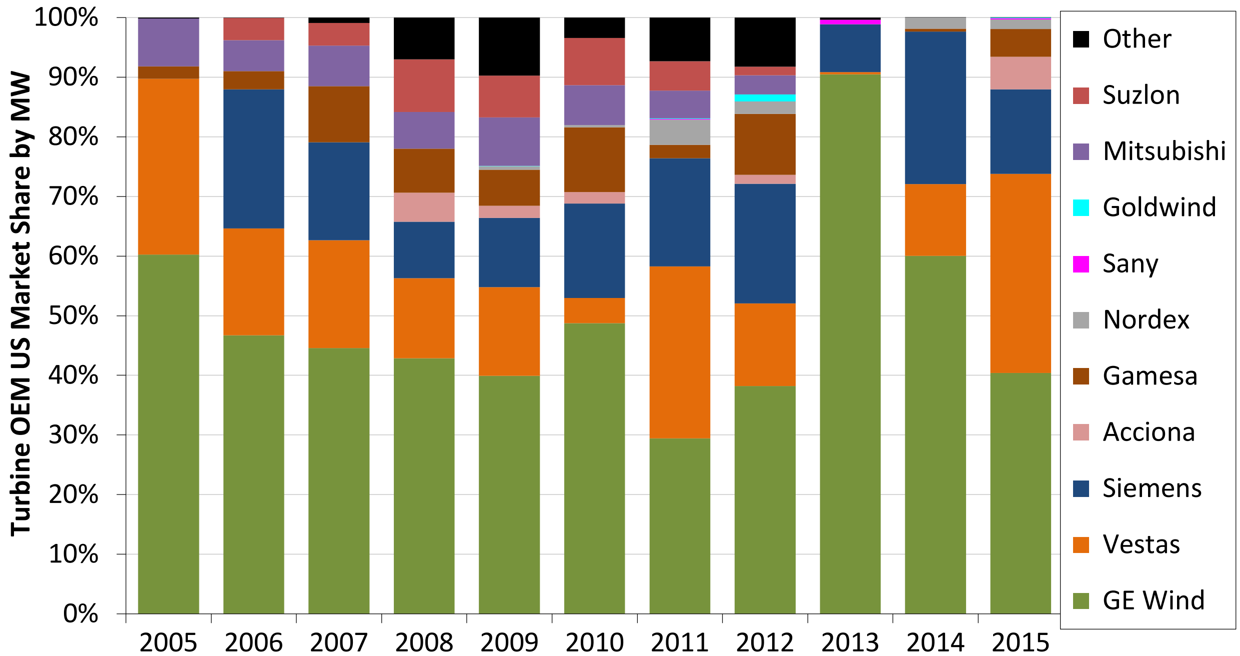
Figure 8. Wind power capacity in 34 selected interconnection queues, by region

As a measure of the near-term development pipeline, ABB (2016) estimates that—as of June 2016—approximately 29 GW of wind power capacity could be characterized in one of three ways: (a) under construction or in site preparation (8 GW); (b) in development and permitted (11 GW); or (c) in development with a pending permit and/or regulatory applications (9 GW). These totals are similar to last year at approximately the same time (June 2015), indicating that the development pipeline remains strong. AWEA (2016b), meanwhile, reports that more than 15 GW of wind power capacity was under construction or at an advanced stage of development at the end of the first quarter of 2016. Supporting these figures, EIA (2016c) reports over 15 GW of planned wind power additions for 2016 and 2017.

3. Industry Trends

GE and Vestas captured 73% of the U.S. wind power market in 2015

Of the 8,598 MW of wind installed in 2015, 40% (3,468 MW) deployed turbines from GE Wind, with Vestas coming in second (2,870 MW, 33% market share), followed by Siemens (1,219 MW, 14%) (Figure 9 and Table 3).[16] Other suppliers included Acciona (465 MW), Gamesa (402 MW), Nordex (138 MW), Sany (20 MW), and Goldwind (8 MW). Some recent OEM consolidation has also occurred, with Nordex merging with Acciona, GE acquiring Alstom, and more recently in mid-2016, Siemens merging with Gamesa.



Source: AWEA project database

Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2015

According to Navigant (2016a), Goldwind and Vestas were the top two suppliers of turbines worldwide in 2015, followed by GE, Siemens, and Gamesa. On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with five of the top 10 spots in the ranking; to date, however, the growth of Chinese turbine manufacturers has been based almost entirely on sales to the Chinese market (though both Goldwind and Sany turbines were installed in the U.S. in 2015, with a limited number of Chinese turbines also installed in earlier years). Other than GE, no other U.S.-owned utility-scale turbine manufacturer plays a meaningful role in global or U.S. large-wind-turbine supply.

[16] Market share is reported in MW terms and is based on project installations in the year in question.

Table 3. Annual U.S. Turbine Installation Capacity by Manufacturer

Manufacturer	Turbine Installations (MW)										
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
GE Wind	1,431	1,146	2,342	3,585	3,995	2,543	2,006	5,016	984	2,912	3,468
Vestas	699	439	948	1,120	1,489	221	1,969	1,818	4	584	2,870
Siemens	0	573	863	791	1,162	828	1,233	2,638	87	1,241	1,219
Acciona	0	0	0	410	204	99	0	195	0	0	465
Gamesa	50	74	494	616	600	566	154	1,341	0	23	402
Nordex	0	0	3	0	63	20	288	275	0	90	138
Sany	0	0	0	0	0	0	10	2	8	0	20
Goldwind	0	0	0	0	5	0	5	155	0	0	8
Mitsubishi	190	128	356	516	814	350	320	420	0	0	0
Suzlon	0	92	198	738	702	413	334	187	0	0	0
Other	4	2	50	587	973	180	502	1,086	4	2	2
TOTAL	2,374	2,457	5,253	8,362	10,005	5,216	6,820	13,131	1,087	4,854	8,598

Source: AWEA project database

The manufacturing supply chain continued to adjust to swings in domestic demand for wind equipment

As the cumulative capacity of U.S. wind projects has grown over the last decade, foreign and domestic turbine equipment manufacturers have localized and expanded operations in the United States. Yet, the wind industry's domestic supply chain continues to deal with conflicting pressures: an upswing in near- to medium-term expected growth, but also strong international competitive pressures and possible reduced demand over time as the PTC is phased down. As a result, though many manufacturers increased the size of their U.S. workforce in 2015, market expectations for significant supply-chain expansion have become more pessimistic.

Figure 10 presents a non-exhaustive list of the more than 145 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2015, focusing on the utility-scale wind market.[17] Figure 11 segments those facilities by major component.

Only one new wind-related manufacturing facility opened in 2015: MM Composite, a composite parts manufacturer that had previously operated solely within the Siemens Fort Madison, Iowa blade facility. Located in Mount Pleasant, Iowa, the new facility will allow MM Composites to increase its overall workforce. Also announced in 2015 was a planned 2016 opening of a tower manufacturing facility in Amarillo, Texas by GRI Renewables. That facility is expected to employ up to 300 workers and manufacture up to 400 towers annually when it reaches full

[17] The data on existing, new, and announced manufacturing facilities presented here differ from those presented in AWEA (2016a) due, in part, to methodological differences. For example, AWEA includes data on a large number of smaller component suppliers that are not included in this report; the figure presented here also does not include research and development and logistics centers, or materials suppliers. As a result, AWEA (2016a) reports a much larger number of wind-related manufacturing facilities, over 500 in total.

production. At the same time, at least three existing wind turbine or component manufacturing facilities were consolidated, closed, or stopped serving the industry in 2015.

Notwithstanding the recent supply chain consolidation and slow additions of new facilities, there remain a large number of domestic manufacturing facilities. Additionally, several manufacturers either expanded their workforce in 2015 to meet demand (e.g., Vestas, LM Windpower, MFG Aberdeen), remodeled facilities to meet industry standards (e.g., LM Windpower,), or began expansions of existing facilities (e.g., Vestas, MFG Aberdeen). As also shown in Figure 10, turbine and component manufacturing facilities are spread across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers (OEMs). However, even states that are relatively far from major wind power markets have manufacturing facilities. Most states in the Southeast, for example, have wind manufacturing facilities despite the fact that there are few wind power projects in that region. Workforce considerations, transportation costs, and state and local incentives are among the factors that typically drive location decisions.

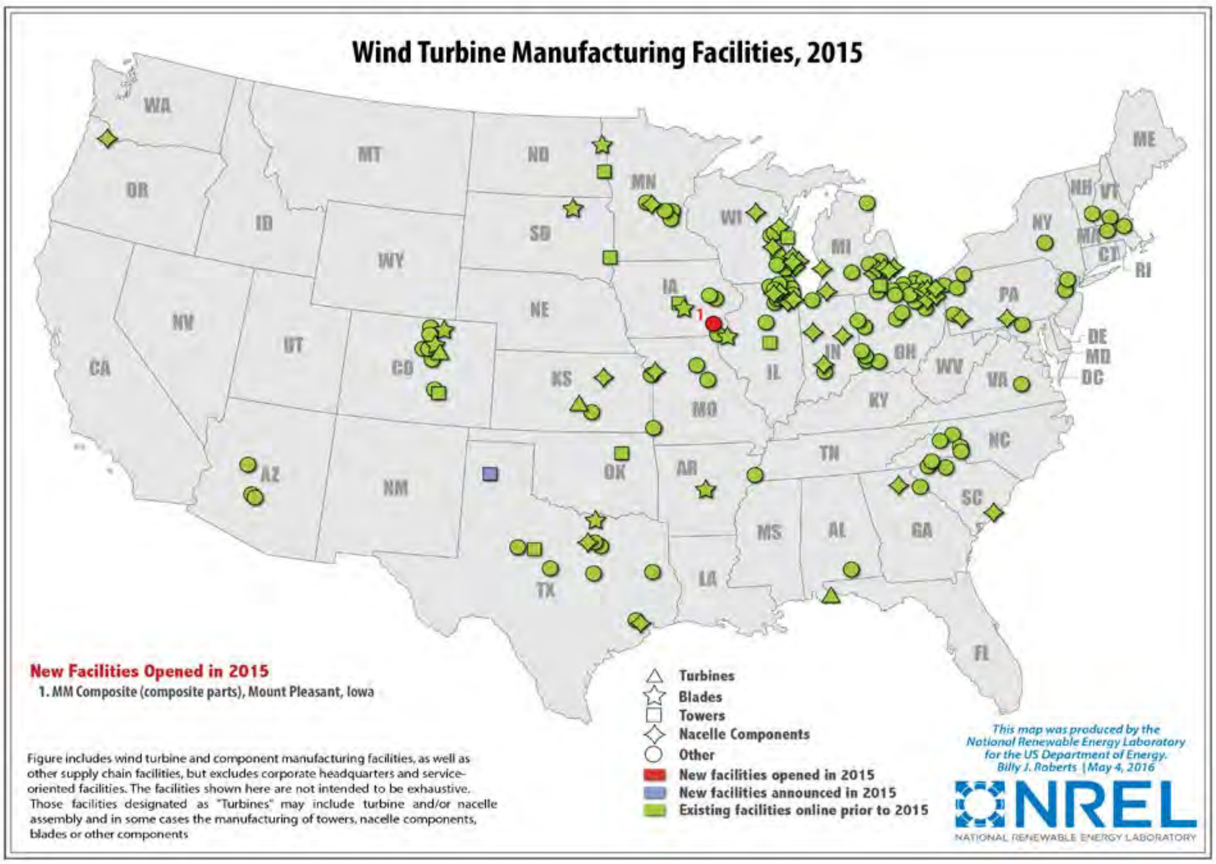
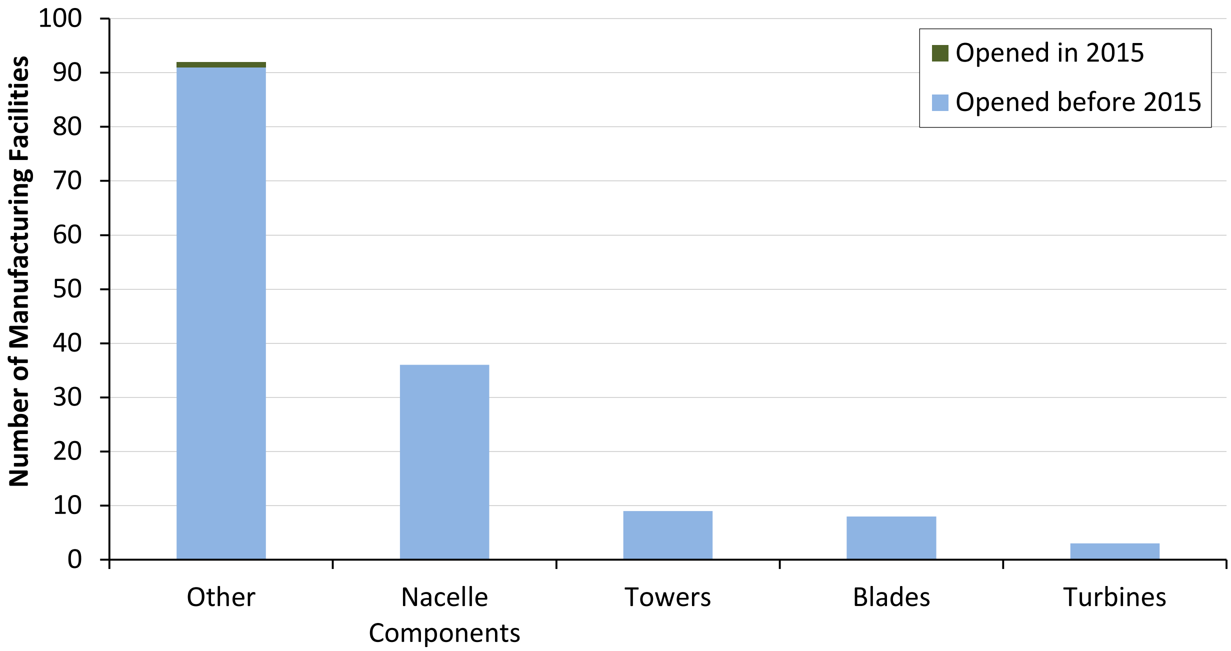


Figure 10. Location of existing and new turbine and component manufacturing facilities

Among the many other facets of the domestic supply chain, in 2010, 9 of the 11 wind turbine OEMs with the largest shares of the U.S. market owned at least one domestic manufacturing facility (Acciona, Clipper, DeWind, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas).[18] Since that time, a number of these facilities have been closed, in part reflecting the increased concentration of the U.S. wind industry among the three top OEMs, demand uncertainty, and a desire to consolidate production at centralized facilities overseas in order to gain economies of scale. For example, though no final decision has been announced regarding Alstom's Amarillo, Texas facility, the plant was idled when the GE/Alstom merger was announced. Similarly, the Nordex/Acciona merger has left the future of the Acciona West Branch, Iowa facility in question. The plant is currently idled. Nonetheless, the three major OEMs active in the U.S. market (GE, Vestas, Siemens) still had one or more operating manufacturing facilities in the United States at the end of 2015. In contrast, a decade earlier (2004), there was only one active utility-scale wind energy OEM assembling nacelles in the United States (GE).



Note: Manufacturing facilities that produce multiple components are included in multiple bars. "Other" includes facilities that produce items such as: enclosures, power converters, slip-rings, inverters, electrical components, tower internals, climbing devices, couplings, castings, rotor hubs, plates, walkways, doors, bearing cages, fasteners, bolts, magnetics, safety rings, struts, clamps, transmission housings, embed rings, electrical cable systems, yaw/pitch control systems, bases, generator plates, slew bearings, flanges, anemometers, and template rings.

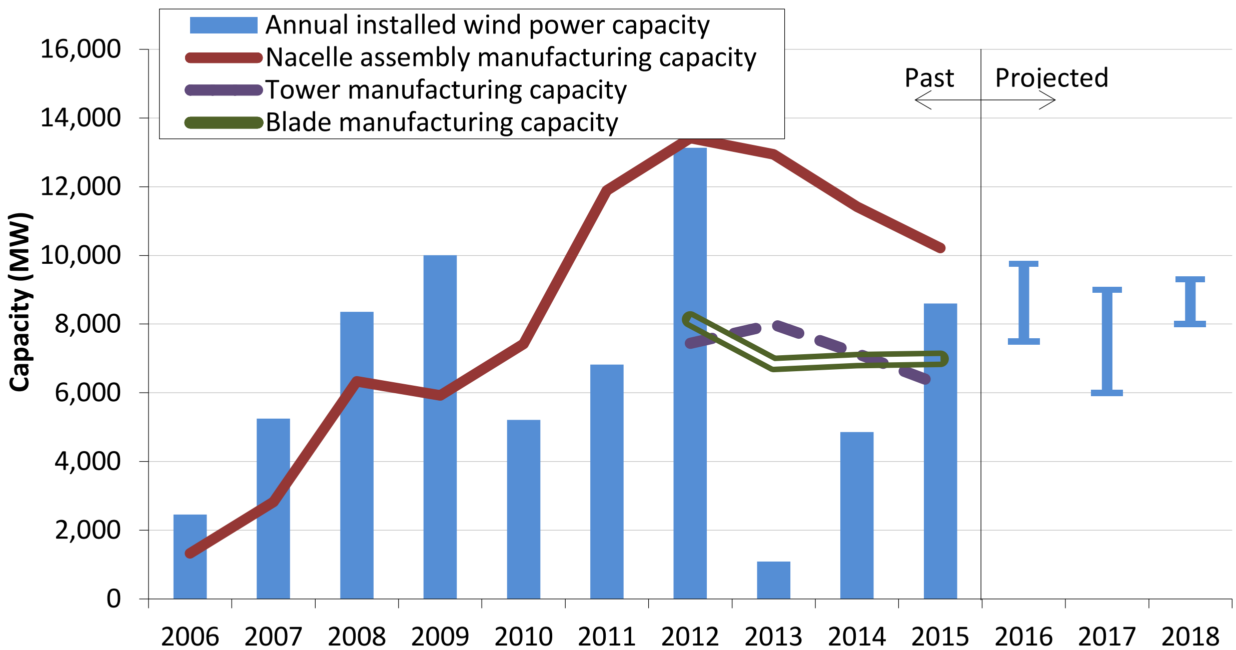
Source: National Renewable Energy Laboratory

Figure 11. Number of operating wind turbine and component manufacturing facilities in the U.S.

In aggregate, domestic turbine nacelle assembly capability—defined here as the "maximum" nacelle assembly capability of U.S. plants if all were operating at maximum utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, before dropping to roughly 10 GW in 2015 (Figure 12; Bloomberg NEF 2015a, AWEA 2016a). In addition, AWEA (2016a) reports that U.S. manufacturing facilities have the capability to produce 10,500 individual blades (~7 GW) and more than 3,100 towers (~6.2 GW) annually. Figure 12 contrasts this

[18] Nacelle assembly is defined here as the process of combining the multitude of components included in a turbine nacelle to produce a complete turbine nacelle unit.

equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future U.S. installations (see Chapter 9, “Future Outlook”). It demonstrates that domestic manufacturing capability for blades, towers, and nacelle assembly is reasonably well balanced against anticipated near-term market demand. Such comparisons should be made with care, however, because maximum factory utilization is uncommon, and because turbine imports into and exports from the United States also impact the balance of supply and demand.



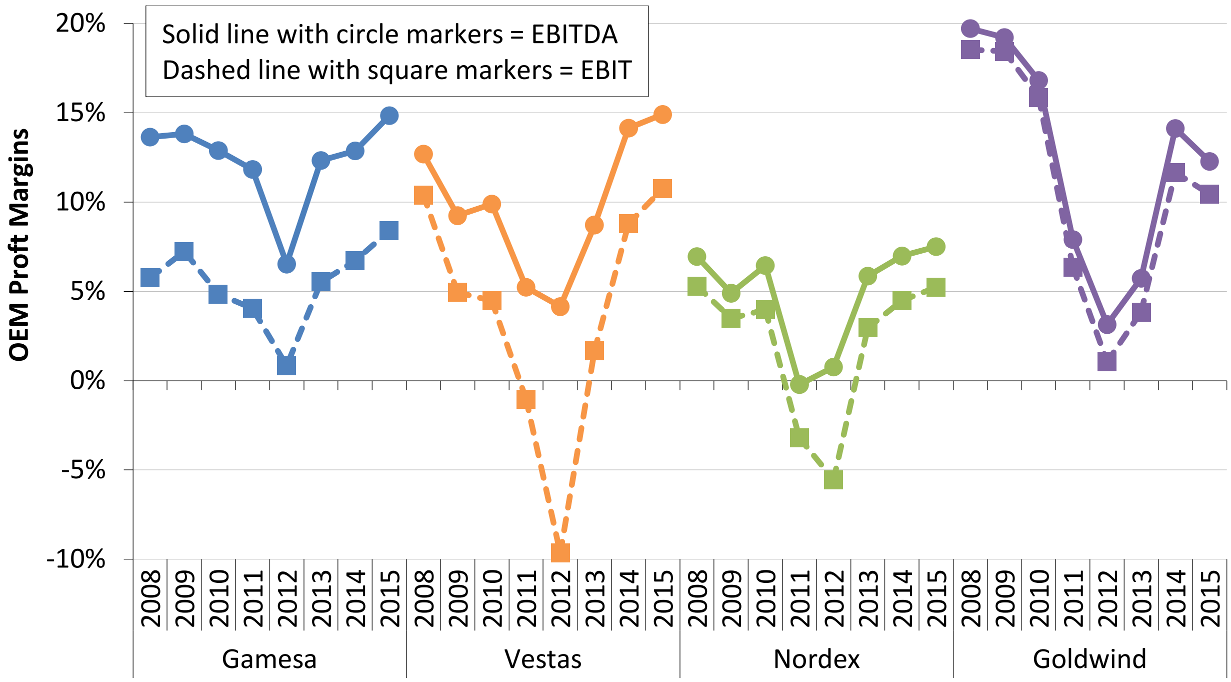
Source: AWEA, Bloomberg NEF, EIA, IHS, Navigant, MAKE, UBS, Berkeley Lab

Figure 12. Domestic wind manufacturing capability vs. U.S. wind power installations

Fierce competition throughout the supply chain has caused many manufacturers to execute cost-cutting measures globally and domestically in recent years. As a result of these cost savings, coupled with booming demand, the profitability of turbine OEMs has generally rebounded over the last three years, after a number of years in decline (Figure 13).[19] Moreover, with recent and near-term expected continued strong growth in U.S. wind installations, wind-related job totals in the U.S. reached a new all-time high in 2015. AWEA (2016a) estimates that the wind industry employed 88,000 full-time[20] workers in the United States at the end of 2015—an increase of more than 15,000 from the end of 2014. The 88,000 jobs include, among others, those in the manufacturing and supply chain (~21,000); construction, development, and transportation (~38,000); and plant operations (~19,000). Consistent with the growth in wind power construction activity, the largest increase from 2014 to 2015 was seen in the construction, development, and transportation category.

[19] Figure 13 only reports data for those OEMs that are “pure-play” wind turbine manufacturers. GE and Siemens—among the largest turbine suppliers in the U.S. market (along with Vestas)—are not included because they are multi-national conglomerates that do not report segmented financial data for their wind turbine divisions. Figure 13 depicts both EBIT (i.e., “earnings before interest and taxes,” also referred to as “operating profit”) and EBITDA (i.e., “earnings before interest, taxes, depreciation, and amortization”) margins.

[20] Jobs are reported as full-time equivalents. For example, two people working full-time for 6 months are equal to one full-time job in that year.



Note: EBITDA = earnings before interest, taxes, depreciation and amortization

Source: OEM annual reports and financial statements

Figure 13. Turbine OEM global profitability over time

Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports

The U.S. wind sector is reliant on imports of wind equipment, though the level of dependence varies by component: some components have a relatively high domestic share, whereas other components remain largely imported. These trends are revealed, in part, by data on wind power equipment trade from the U.S. Department of Commerce.[21]

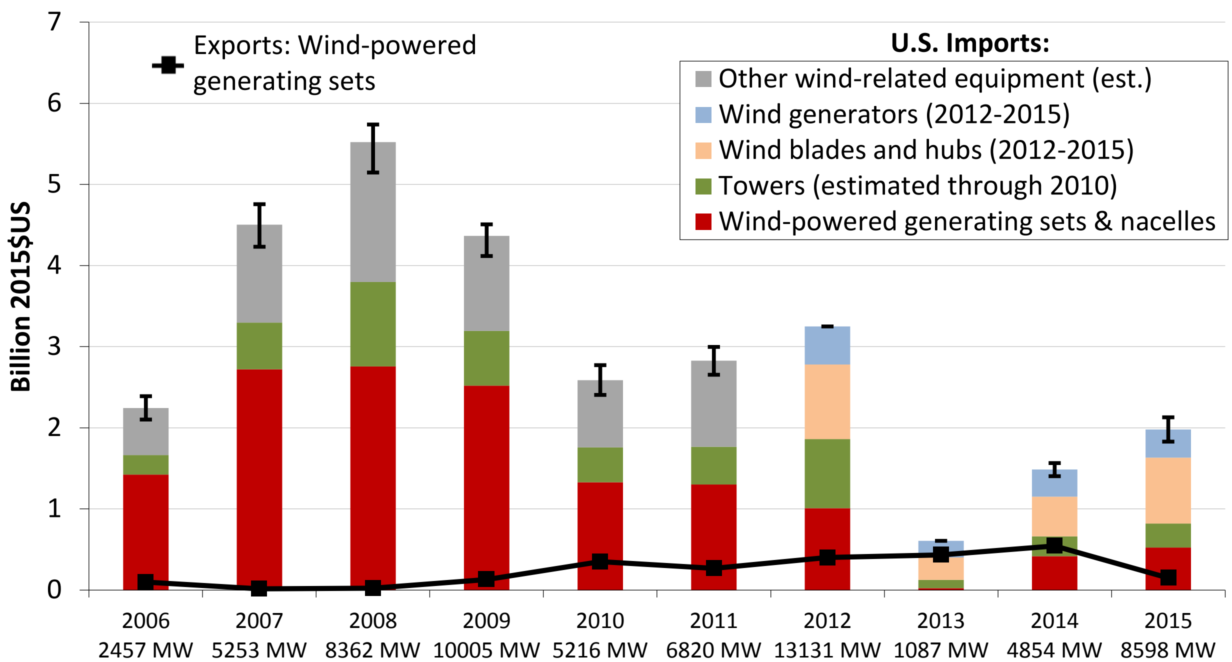
Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating sets and nacelles (i.e., nacelles with blades, nacelles without blades, and, when imported as part of the same transaction, other turbine components) as well as imports of select turbine components that are shipped separately from the generating sets and nacelles.[22] The selected wind turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (and generator parts), and blades and hubs.

Import estimates should be viewed with particular caution because the underlying data used to produce the Figure 14 are based on trade categories that are not all exclusive to wind energy (e.g., they could include generators for non-wind applications). Some of the import estimates

[21] See the appendix for further details on data sources and methods used in this section, including the specific trade codes considered.

[22] Wind turbine components such as blades, towers, and generators are included in the data on wind-powered generating sets and nacelles if shipped in the same transaction. Otherwise, these component imports are reported separately.

shown in Figure 14 therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. The error bars in Figure 14 account for uncertainty in these assumed fractions. In 2012 and 2013, all trade categories shown were either specific to or largely restricted to wind power, and so no error bars are shown. After 2013, only nacelles (when shipped alone) are included in a trade category that is not largely exclusive to wind, and so the error bars shown for 2014 and 2015 only reflect the uncertainty in nacelle imports. More generally, as noted earlier, Figure 14 excludes comprehensive data on the import of wind equipment, as not all such equipment is clearly identified in trade categories. The impact of this omission on import and domestic content is discussed later.



Source: Berkeley Lab analysis of data from USITC DataWeb: http://dataweb.usitc.gov

Figure 14. Estimated imports of wind-powered generating sets, towers, generators, and blades and hubs, as well as exports of wind-powered generating sets and towers and lattice masts

As shown, the estimated imports of tracked wind-related equipment into the United States substantially increased from 2006–2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then dropping sharply in 2013 with the simultaneous drop in U.S. wind installations. In 2014 and 2015, as U.S. wind installations bounced back, so did imports of wind-related turbine equipment. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind power capacity installations, and changes in wind turbine prices. Because imports of wind turbine component parts occur in additional, broad trade categories different from those included in Figure 14, the data presented here understate the aggregate amount of wind equipment imports into the United States.

Figure 14 also shows that exports of wind-powered generating sets from the United States have generally increased over time, rising from just $16 million in 2007 to $544 million in 2014. The year 2015 was a notable exception to this trend, however, with exports falling to $149 million. The largest destination markets for these exports over the entire 2006–2015 timeframe were

Canada (60%) and Brazil (27%); 2015 exports were also dominated by Canada (52%) and Brazil (19%). U.S. exports of 'towers and lattice masts' in 2015 totaled an additional $63 million (down from a peak of $170 million in 2012), with 41% of these exports going to Canada and 28% going to Uruguay. The trade data for tower exports do not differentiate between tubular towers (primarily used in wind power applications) and other types of towers, unlike the import classification for towers from 2011–2015, which does differentiate. Although some of the tower exports are wind-related, the exact proportion is not known. Other wind turbine component exports are not reported because such exports are likely a small and/or uncertain fraction of broader trade category totals. Despite overall growth in exports from 2007 to 2014, the United States remained a sizable net importer of wind turbine equipment over this period. The sharp decrease in exports in 2015 may indicate that the fast-rising U.S. wind market absorbed much of the local production of wind turbine equipment.

Figure 15 shows the total value of selected, tracked wind-specific imports to the United States in 2015, by country of origin, as well as the main "districts of entry"[23]: forty percent of the import value in 2015 came from Asia (led by China), 38% from Europe (led by Spain), and 22% from the Americas (led by Brazil). The principal districts of entry for this wind equipment were Houston-Galveston, TX (29%), Great Falls, MT (16%), and Laredo, TX (9%).

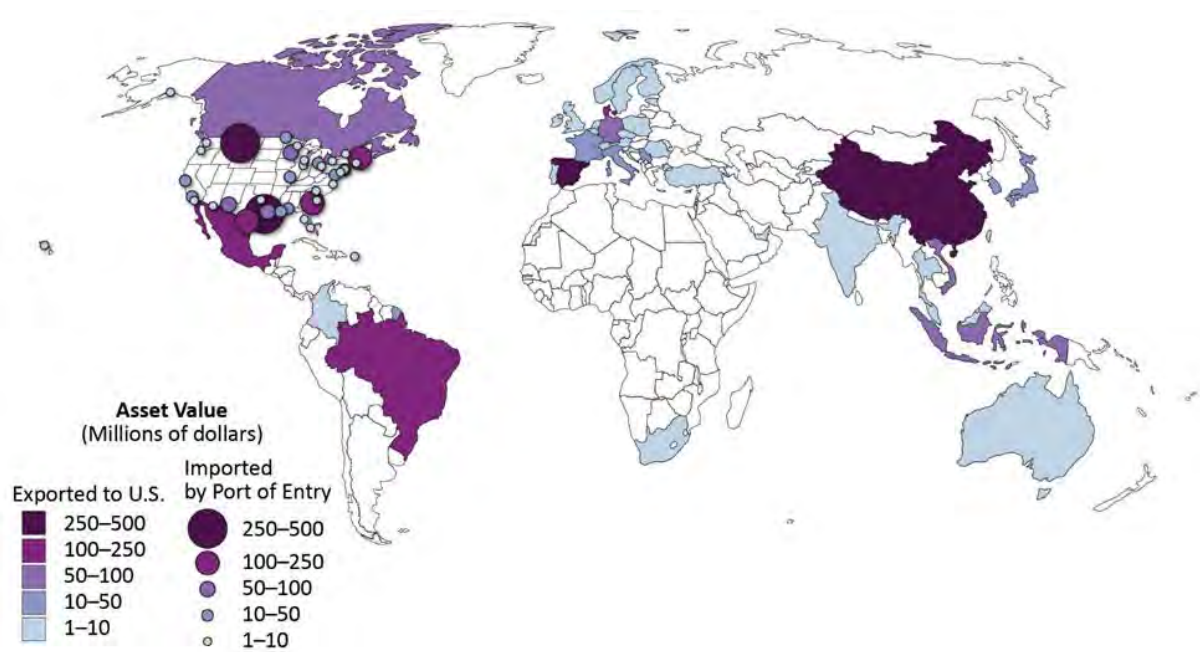
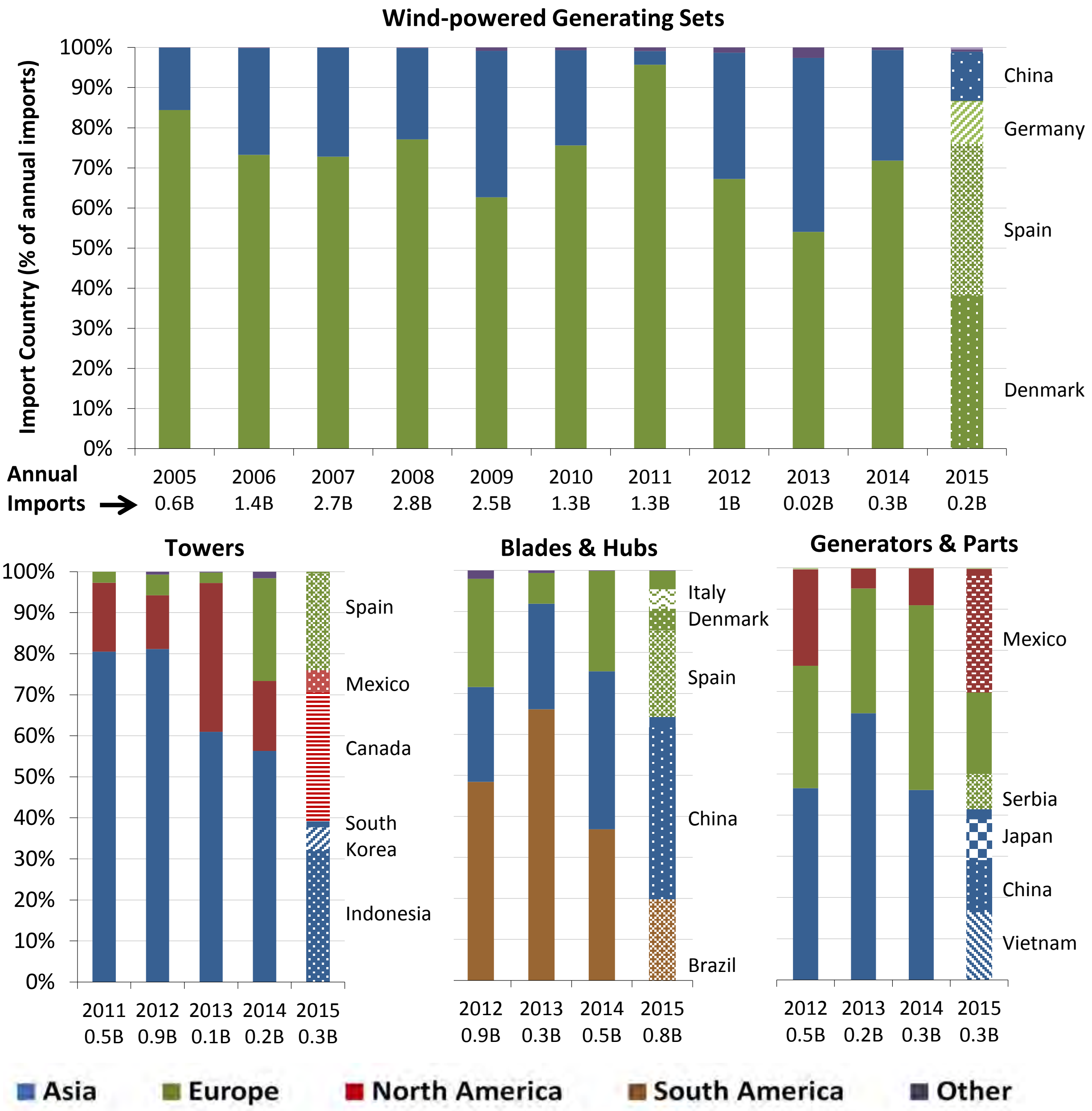


Figure 15. Summary map of tracked wind-specific imports in 2015: countries of origin and U.S. districts of entry

[23] The trade categories included here are all of the wind-specific import categories for 2015 (see the appendix for details), and so the 2015 total import volume considered in Figure 15 differs from that in Figure 14. As noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included in this analysis; additionally, in the case of nacelles without blades, the trade code is not exclusive to wind and so related imports are not included in Figure 15 (though they are included in Figure 14). As such, the data presented in Figure 15 understate the aggregate amount of wind equipment imports into the United States. Note also that "districts of entry" as used here refers to, in some cases, multiple points of entry located in the same geographic region; note also that goods may arrive at districts of entry by land, air, or sea.

Looking behind the import data in more detail, and focusing on those trade codes that are largely exclusive to wind equipment, Figure 16 shows a number of trends over time in the origin of U.S. imports of wind-powered generating sets, tubular towers, wind blades and hubs, and wind generators and parts.



Source: Berkeley Lab analysis of data from USITC DataWeb: http://dataweb.usitc.gov

Figure 16. Origins of U.S. imports of selected wind turbine equipment

For wind-powered generating sets, the primary source markets during 2005–2015 have been Europe and—to a lesser extent—Asia, with leading countries largely being those that are home to the major international turbine manufacturers: Denmark, Spain, Japan, India, and Germany. In 2015, imports of wind-powered generating sets were dominated by Denmark, Spain, Germany, and China, though the total import value was relatively low ($227 million). The share of imports of tubular towers from Asia was over 80% in 2011 and 2012 (almost 50% from China), with much of the remainder from Canada and Mexico. From 2013-2015, not only did the total import value decline relative to earlier years, but there were almost no imports from China and Vietnam—likely a result of the tariff measures that were imposed on wind tower manufacturers from these countries. Tower imports in 2015 came from a mix of countries from Asia (e.g., Indonesia and South Korea), Europe (e.g., Spain), and North America (e.g., Canada and Mexico). With regards to wind blades and hubs, China, Spain, and Brazil dominate as source markets (various other European countries play a somewhat lesser role), with China steadily increasing its market share over time. Finally, the import origins for wind-related generators and generator parts were distributed across a number of largely Asian and European countries, in addition to Mexico, from 2012 through 2015.

Because trade data do not track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between import and domestic content. The trade data also do not allow for a precise estimate of the domestic content of specific wind turbine components. Nonetheless, based on those data and a variety of assumptions, Table 4 presents rough estimates of the domestic content for a subset of the major wind turbine components used in U.S. wind power projects in 2015. As shown, domestic content is strong for large, transportation-intensive components such as towers, blades and hubs, and nacelle assembly.

Table 4. Approximate Domestic Content of Major Components in 2015

Towers	Blades & Hubs	Nacelle Assembly
80-85%	50-70%	> 85% of nacelle assembly

These figures, however, understate the wind industry's reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured in Table 4, including wind equipment (such as generator, mainframe, converter, pitch and yaw systems, main shaft, bearings, bolts, controls) and manufacturing inputs (such as foreign steel and oil used in domestic manufacturing).[24]

An alternative interview-based approach to estimating domestic content indicates overall domestic content of all wind turbine equipment used in the United States of about 40% in 2012. When considering balance-of-plant costs as well, overall project-level domestic content in 2012 reached roughly 60%. These interviews further revealed that domestic content is relatively high for blades, towers, nacelle assembly and nacelle covers, supporting the more recent analysis presented in Table 4. The domestic content of most of the equipment internal to the nacelle—much of which is not specifically tracked in wind-specific trade data—is considerably lower, typically well below 20%.[25]

[24] On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting domestic fraction would be higher than that presented here.
[25] The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.

The project finance environment remained strong in 2015

Most of the financing deals that closed in 2015 stemmed from the Tax Increase Prevention Act of 2014, which in late December 2014 extended the PTC's "construction start" deadline for one additional year, from the end of 2013 to the end of 2014 (effectively providing developers with just two weeks during which to start construction in order to qualify for the PTC). Subsequently, in March 2015, the IRS extended its safe harbor guidance for another year as well, enabling wind projects that had met the end-of-2014 construction start deadline to qualify for the PTC (without having to prove continuous effort) if online by the end of 2016.

As a result, 2015 was a big, somewhat rushed year for wind project finance. This was particularly true in the tax equity market, where project sponsors raised anywhere from $5.9 billion (AWEA 2016a) to $6.4 billion (Chadbourne & Parke 2016b) of new tax equity in 2015—up slightly from $5.7-$5.8 billion in 2014 and the largest single-year amount on record. On the debt side, AWEA (2016a) reports that 2,078 MW of new and existing wind capacity raised $2.9 billion in debt in 2015, up from the $2.2 billion raised in 2014, but well below the higher levels seen in previous years when the Section 1603 grant was available.[26] Given the short lead time with the December 2014 PTC extension, most of the projects financed in 2015 will achieve commercial operations in 2016.

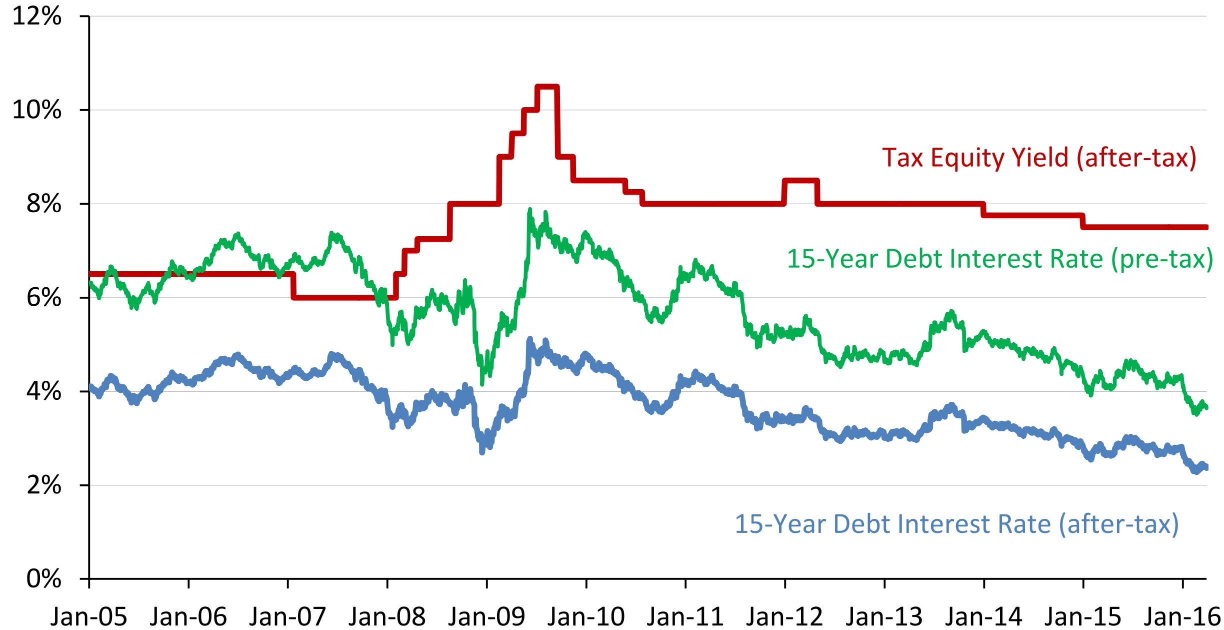
As shown in Figure 17, tax equity yields drifted slightly lower in 2015, to just below 8% on an after-tax unlevered basis. Debt interest rates bounced around somewhat, but ultimately headed lower throughout the year, with the 15-year benchmark fixed all-in interest rate starting off 2016 below 4% (~2.5% on a post-tax basis[27]) for the first time in the more-than-eleven-year history of the graph. As a result, the spread between tax equity yields and 15-year term debt (on a post-tax basis) stood at more than 5% as of May 2016—its highest level since 2009. The intransigence of this spread continues to vex those wind project owners that lack tax appetite, and so must finance their projects with relatively expensive tax equity rather than increasingly cheap debt (Chadbourne & Parke 2016a). Partnership flip structures[28] remained the dominant tax equity vehicle, while banks continued to focus more on shorter-duration loans (7–10 year mini-perms

[26] From 2009–2012 (i.e., the years in which the Section 1603 grant was available), some project sponsors who lacked tax appetite financed their projects using the grant in combination with project-level term debt, carrying forward depreciation losses as necessary and foregoing tax equity altogether. With the grant no longer available, most projects now elect the PTC (instead of the ITC), and rely upon third-party tax equity investors to monetize the losses and credits. Because most tax equity investors will not allow leverage on projects in which they invest (Chadbourne & Parke 2016a, 2016b), the expiration of the Section 1603 grant for wind and the correspondingly greater reliance on the PTC could be a contributor to the decline in debt raised by new wind projects in 2013 through 2015.

[27] The returns of equity investors in renewable projects are often expressed on an after-tax basis, because of the significant value that federal tax benefits provide to such projects (e.g., after-tax returns can be higher than pre-tax returns). In order to accurately compare the cost of debt (which is quoted on a pre-tax basis) to tax equity (described in after-tax terms), one must convert the pre-tax debt interest rate to its after-tax equivalent (to reflect the tax-deductibility of interest payments) by multiplying it by 65%, or 100% minus an assumed marginal tax rate of 35%.

[28] A "partnership flip" is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own the project. Initially, allocations of tax benefits are skewed heavily in favor the tax equity partner (which is able to efficiently monetize the tax benefits), but eventually "flip" in favor of the project sponsor partner once the tax benefits have been largely exhausted. Cash is also allocated between the partners, with one or more "flip" events, but in recent years has been increasingly directed towards the project sponsor to the extent possible, in order to support back leverage or dividend payments to YieldCo investors.

remained the norm[29]), leaving longer-duration, fully amortizing loans to institutional lenders (Chadbourne & Parke 2016b).



Source: Federal Reserve Board (2016), Bloomberg NEF (2016e)

Figure 17. Cost of 15-year debt and tax equity for utility-scale wind projects over time

Looking ahead, financing in both the tax equity and debt markets is likely to remain active in 2016 and beyond, thanks to the five-year tax credit extension (with phase down) that became law in late December 2015 (see Chapter 8, Policy and Market Drivers, for more details on this long-term extension and phase-down). In May 2016, the IRS also increased the safe harbor window from two years to four years, effectively allowing a wind project that starts construction before the end of 2016 and achieves commercial operations before the end of 2020 to qualify for the PTC at full value. The tax credit will progressively diminish for projects that start construction in 2017-2019 (and that achieve commercial operations from 2021-2023), which suggests that 2016 and 2017 could represent the peak of project finance activity for the foreseeable future (see pages 68-69 for a lengthier discussion of the PTC phase down schedule).

IPPs own the vast majority of wind assets built in 2015

Independent power producers (IPPs) own 7,290 MW or 85% of the 8,598 MW of new wind capacity installed in the United States in 2015 (Figure 18). More than 1,000 MW are owned by investor-owned utilities (IOUs), including MidAmerican (502 MW), Xcel Energy (350 MW), Montana-Dakota Utilities (107.5 MW), and Northwestern Energy (80 MW), while publicly

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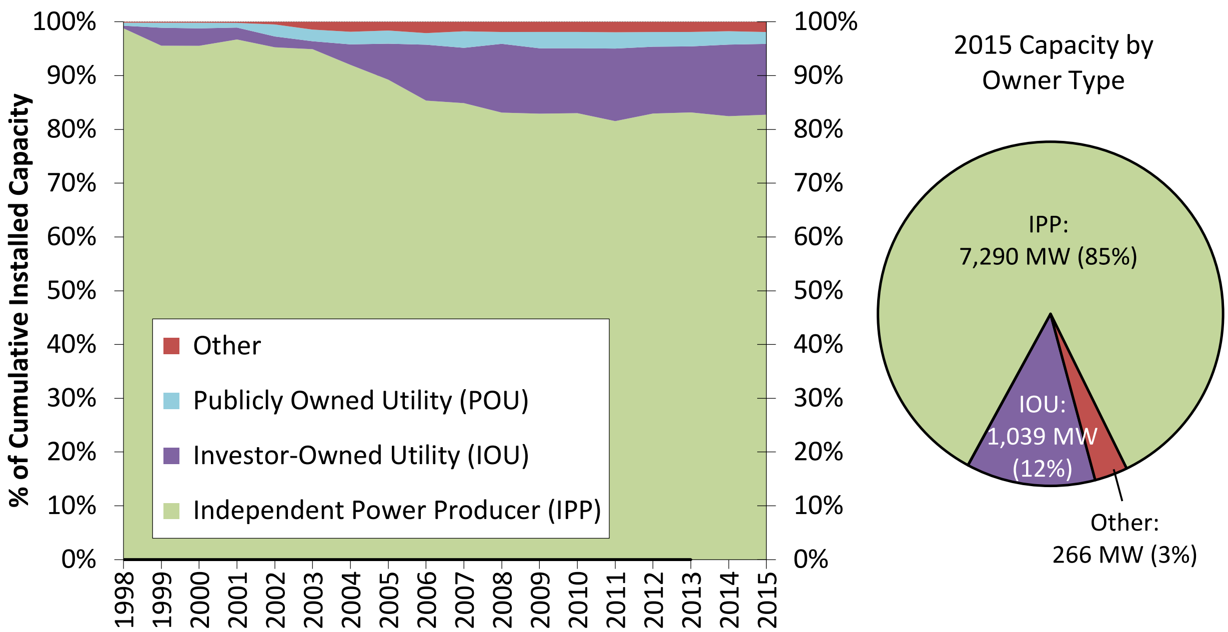
[29] A "mini-perm" is a relatively short-term (e.g., 7–10 years) loan that is sized based on a much longer tenor (e.g., 15–17 years) and therefore requires a balloon payment of the outstanding loan balance upon maturity. In practice, this balloon payment is often paid from the proceeds of refinancing the loan at that time. Thus, a 10-year mini-perm might provide the same amount of leverage as a 17-year fully amortizing loan but with refinancing risk at the end of 10 years. In contrast, a 17-year fully amortizing loan would be repaid entirely through periodic principal and interest payments over the full tenor of the loan (i.e., no balloon payment required and no refinancing risk).

owned utilities (POUs) do not own any of the new wind power capacity brought online in 2015. Finally, 266 MW (3%) fall into the "other" category of projects owned by neither IPPs nor utilities (e.g., towns, schools, businesses, farmers); notably, IKEA owns most of this capacity (263 MW) through two wind projects – one in Illinois and one in Texas.[30] Of the cumulative installed wind power capacity at the end of 2015, IPPs own 83% and utilities own 15% (13% IOU and 2% POU), with the remaining 2% falling into the "other" category.



Source: Berkeley Lab estimates based on AWEA project database

Figure 18. Cumulative and 2015 wind power capacity categorized by owner type

Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales gained ground

Electric utilities continued to be the dominant off-takers of wind power in 2015 (Figure 19), either owning (12%) or buying (48%) power from 60% of the new capacity installed last year (with the 60% split between 37% IOU and 23% POU). On a cumulative basis, utilities own (15%) or buy (53%) power from 68% of all wind power capacity installed in the United States (with the 68% split between 48% IOU and 20% POU).

Merchant/quasi-merchant projects accounted for 29% of all new 2015 capacity and 24% of cumulative capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracts and/or wholesale spot electricity market prices (with the resulting

[30] Many of the "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. According to AWEA (2016a), just 16.9 MW (0.2%) of 2015 wind capacity additions qualified as community wind projects.

price risk commonly hedged over a 10- to 12-year period[31]) rather than being locked in through a long-term PPA.

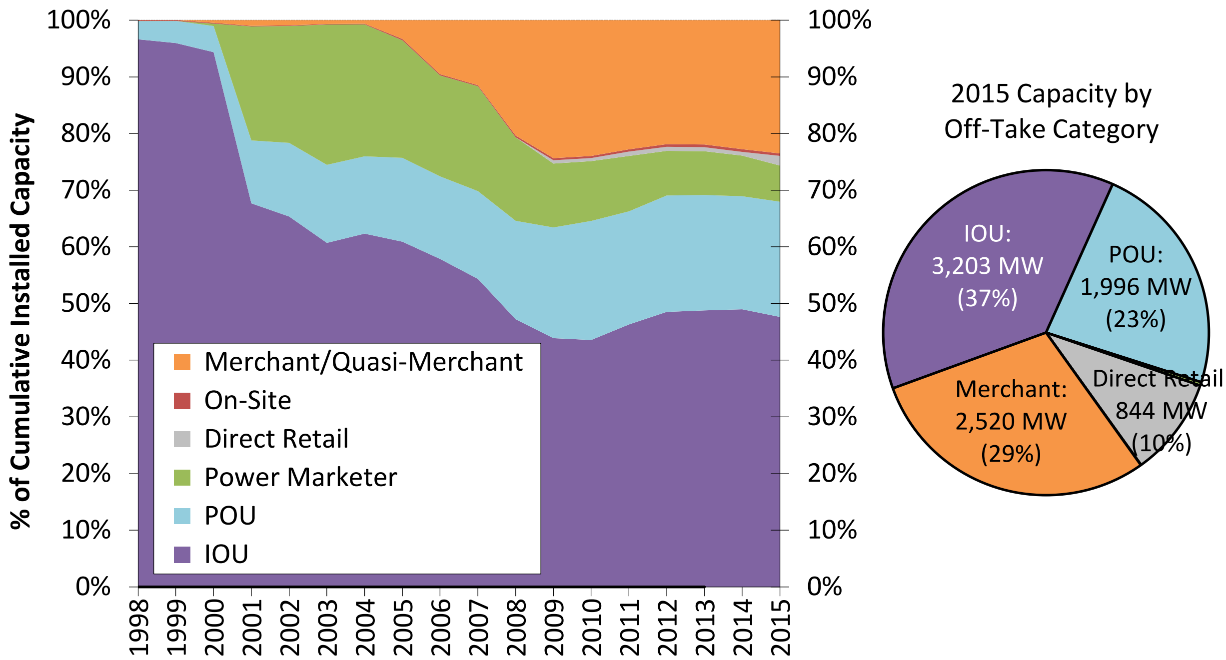
Perhaps the biggest story of 2015 with respect to off-take agreements was the rise of direct retail purchasers of wind (and solar) power, including both corporate and non-corporate off-takers, which together are characterized in Figure 19 as “direct retail” off-takers. Though barely visible in the cumulative portion of Figure 19, direct retail purchases accounted for 844 MW or 10% of the new wind power capacity installed in the United States in 2015. This modest 10% portion is well below the 52% of total wind capacity contracted through PPAs in 2015 that involve non-utility buyers, as reported by AWEA (2016a). The difference is that the 10% pertains to projects that achieved commercial operation in 2015, whereas the 52% pertains to PPAs that were executed in 2015—in many cases for projects that will come online in 2016 or 2017 (or beyond). According to AWEA (2016a), this 52% is up from 23% in 2014 and just 5% in 2013, suggesting that the direct retail segment of Figure 19 should continue to expand in future years.

Power marketers are defined here to include commercial intermediaries that purchase power under contract and then resell that power to others.[32] Though power marketers were very active throughout the first decade of this century following the initial wave of electricity market restructuring, their influence has waned in recent years: just 6% of cumulative wind power capacity in the United States sells to power marketers, down from more than 20% in the early 2000s.

Finally, just 3 MW (0.0%) of the wind power additions in 2015 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.

[31] Hedges are often structured as a “fixed-for-floating” power price swap—a purely financial arrangement whereby the wind power project swaps the “floating” revenue stream that it earns from spot power sales for a “fixed” revenue stream based on an agreed-upon strike price. For some projects, the hedge is structured in the natural gas market rather than the power market.

[32] These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.



Source: Berkeley Lab estimates based on AWEA project database

Figure 19. Cumulative and 2015 wind power capacity categorized by power off-take arrangement

4. Technology Trends

Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term

The average nameplate capacity of the newly installed wind turbines in the United States in 2015 was 2.0 MW, up 180% since 1998–1999 (Figure 20).[33] The average hub height of turbines installed in 2015 was 82.0 meters, up 47% since 1998–1999. Average rotor diameters have increased at a more rapid pace than hub heights in the United States, especially in recent years. The average rotor diameter of wind turbines installed in 2015 was 102.0 meters, up 113% since 1998–1999, which translates into a 355% growth in rotor swept area. These trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.

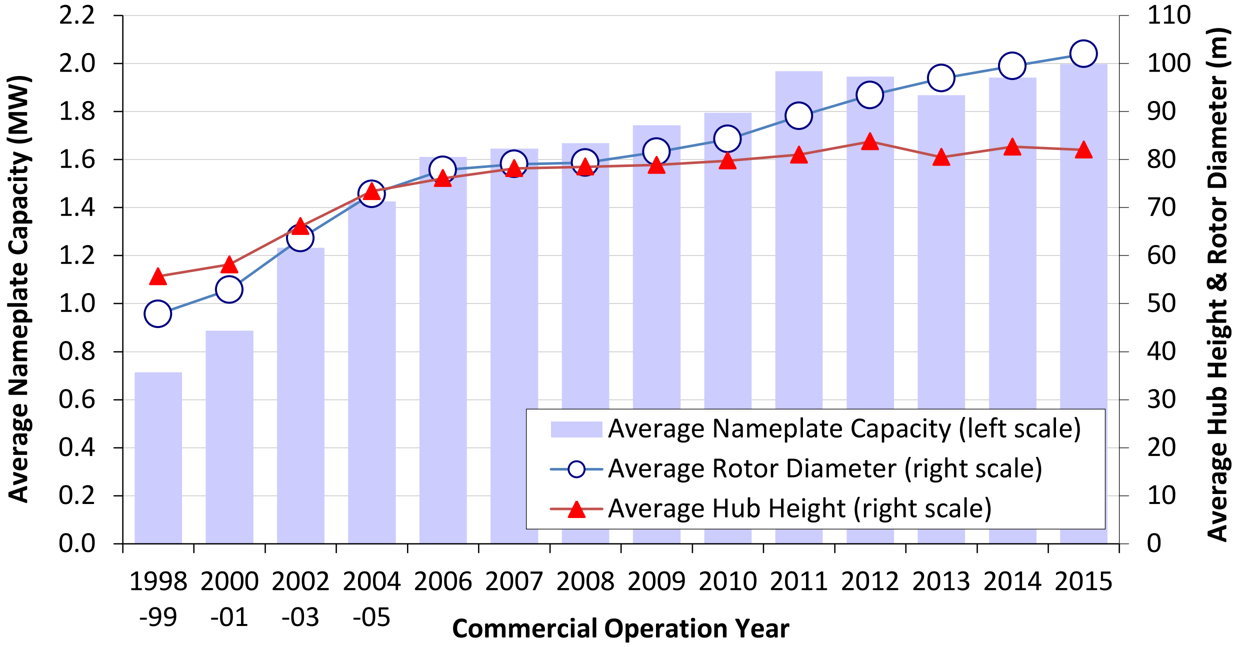


Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height installed during period

Growth in rotor diameter has outpaced growth in nameplate capacity and hub height in recent years

As indicated in Figure 20, and as detailed in Figures 21–23, rotor diameter scaling has been especially significant over the last six years—more so than increases in nameplate capacity and hub heights, both of which have seen a stabilization of the long-term trend in recent years.

[33] Figure 20 (as well as a number of the other figures and tables included in this report) combines data into both 1- and 2-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; although not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects. Though 2013 was a slow year for wind additions, it is shown separately here despite the small sample size.

Starting with turbine nameplate capacity, Figure 21 presents not only the trend in average nameplate capacity (as also shown earlier, in Figure 20) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines has largely held steady since 2011, and the longer-term pace of growth started to slow after 2006. While it took just six years (2000–2005) for MW-class turbines to almost totally displace sub-MW-class turbines, it took another seven years (2006–2012) for multi-MW-class turbines (i.e., 2 MW and above) to gain nearly equal market share with MW-class turbines. The years 2013 and 2014 showed some reversal of that trend, but 2015 was the first year in which > 2 MW turbines were the majority of those installed.

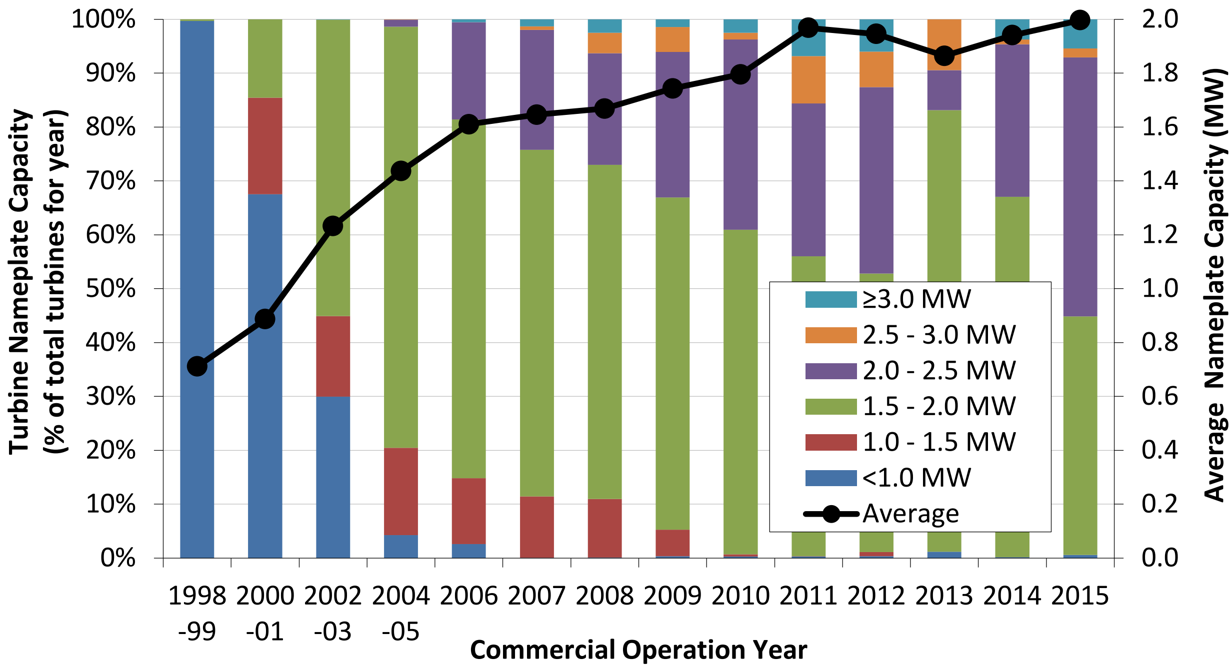


Figure 21. Trends in turbine nameplate capacity

As with nameplate capacity, the average hub height of wind turbines has largely held constant since 2011 (Figure 22). More generally, growth in average hub height has been slow since 2005, with 80 meter towers dominating the overall market. Towers that are 90 meters and taller started to penetrate the market in 2011, however, a trend that has remained steady into 2015, equating to roughly 15% of the market in that year. Finally, although we saw the emergence of >100 meter towers as early as 2007, that segment of the market peaked in 2012 when 16% of newly installed turbines were taller than 100 meters; since 2012, only 1% or less of newly installed turbines in each year (including 2015) have featured towers that tall.

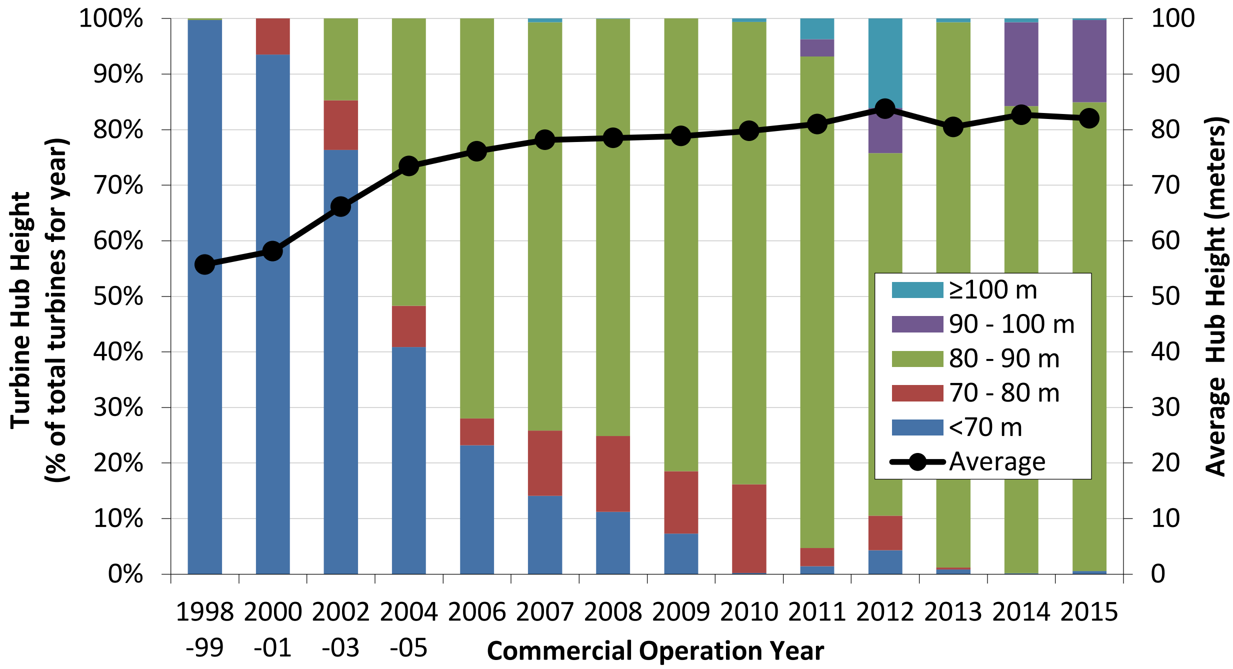


Figure 22. Trends in turbine hub height

The movement towards larger-rotor machines has dominated the U.S. industry in recent years, with OEMs progressively introducing larger-rotor options for their standard turbine offerings and introducing new turbines that feature larger rotors, despite steady average nameplate capacity (Figure 21) and hub heights (Figure 22). As shown in Figure 23, this recent increase has been especially apparent since 2009. In 2008, no turbines employed rotors that were 100 meters in diameter or larger. By 2012, 47% of newly installed turbines featured rotors of at least that diameter, and in 2015 the percentage grew to 86%. Rotor diameters of 110 meters or larger, meanwhile, started penetrating the market in 2012; in 2015, 20% of newly installed turbines featured rotors of that size.

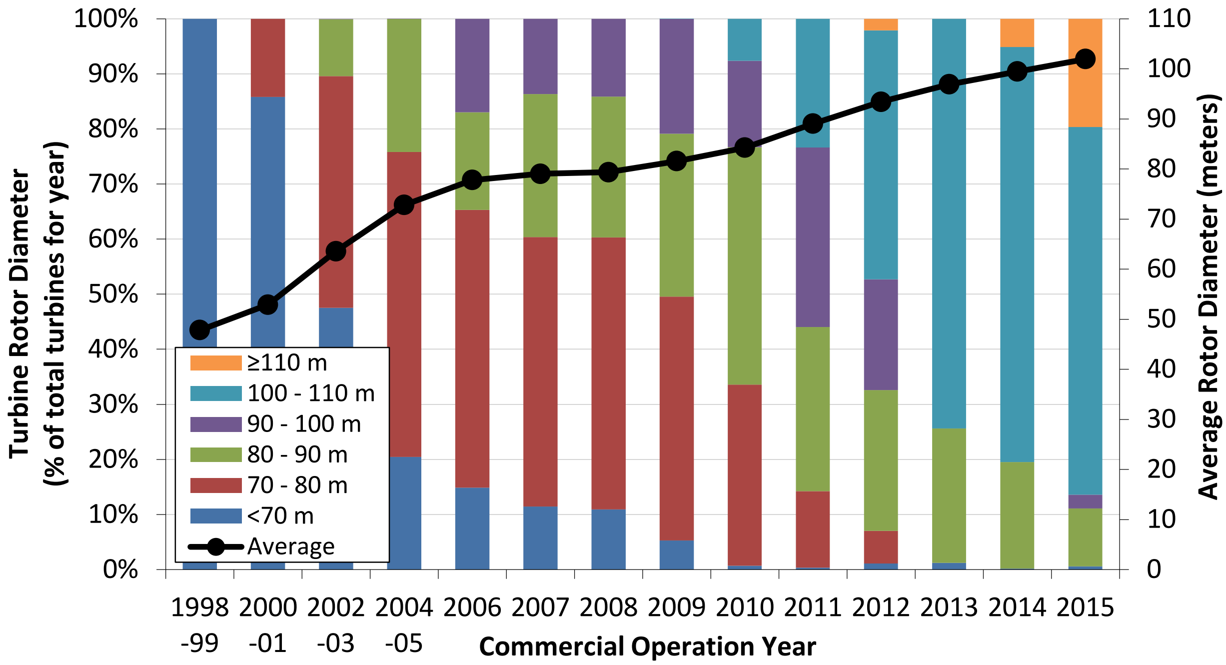


Figure 23. Trends in turbine rotor diameter

Turbines originally designed for lower wind speed sites have rapidly gained market share

Though trends in the average nameplate capacity, hub height, and rotor diameter of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. With growth in average swept area (in m^2) outpacing growth in average nameplate capacity (in W), there has been a decline in the average "specific power" (in W/m^2) among the U.S. turbine fleet over time, from 394 W/m^2 among projects installed in 1998–1999 to 246 W/m^2 among projects installed in 2015 (Figure 24). The decline in specific power was especially rapid from 2001 to 2005 and, more recently, from 2011 to 2015.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity, meaning that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites; they were intended to maximize energy capture in areas where the wind resource is modest, and where large rotor machines would not be placed under undue physical stress. As suggested in Figure 24 and as detailed in the next section, however, such turbines are now in widespread use in the United States—even in sites with high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.

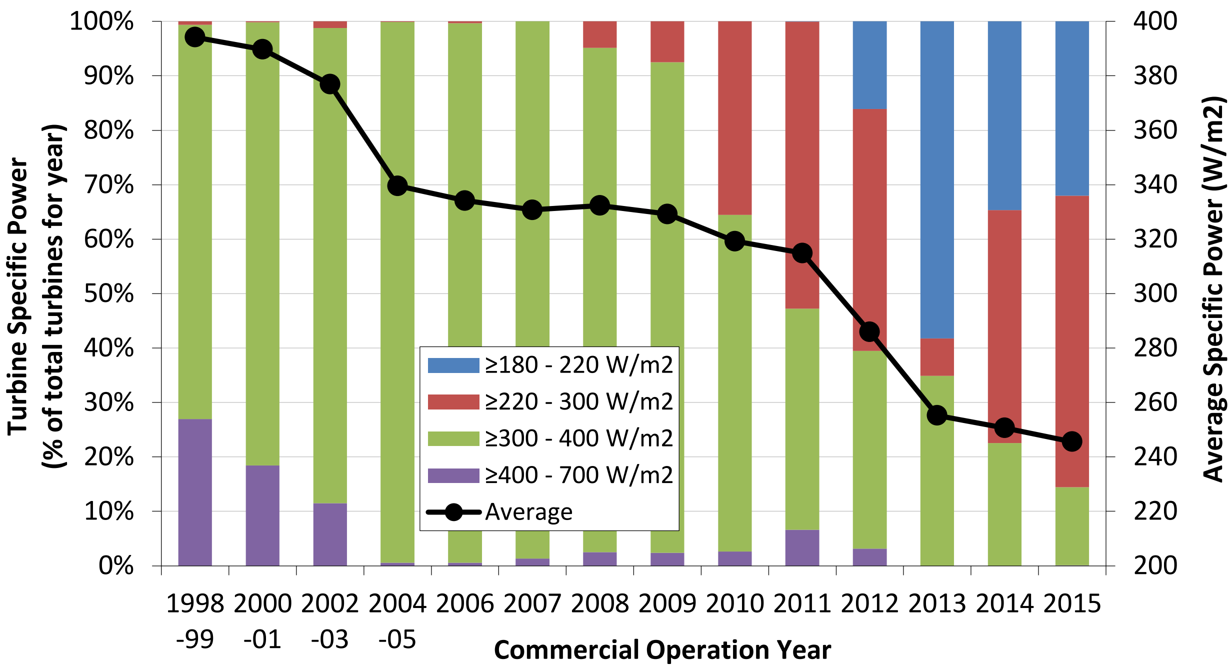


Figure 24. Trends in turbine specific power

Another indication of the increasing prevalence of machines initially designed for lower wind speeds is revealed in Figure 25, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3). Additionally, 9% of the turbines installed in 2015 were Class S, which is outside IEC rating system.[34]

The U.S. wind market has clearly become increasingly dominated by IEC Class 3 turbines in recent years. In 2000–2001, Class 1 machines were prevalent. From 2002 through 2011, Class 2 machines dominated the market. Since 2011, there has been a substantial decline in the use of Class 2 turbines, and a concomitant increasing market share of Class 3 and Class 2/3 turbines. In 2015, 55% of the newly installed turbines were Class 3 machines, 33% were Class 2/3 machines, and less than 3% of turbines were Class 2 or lower.

[34] The IEC 61400 Class "S" turbines in 2015 were GE Wind 1.7 MW turbines with 103 meter rotors on 80 meter towers, installed in five states. These turbines are not included in the reported average IEC class over time.

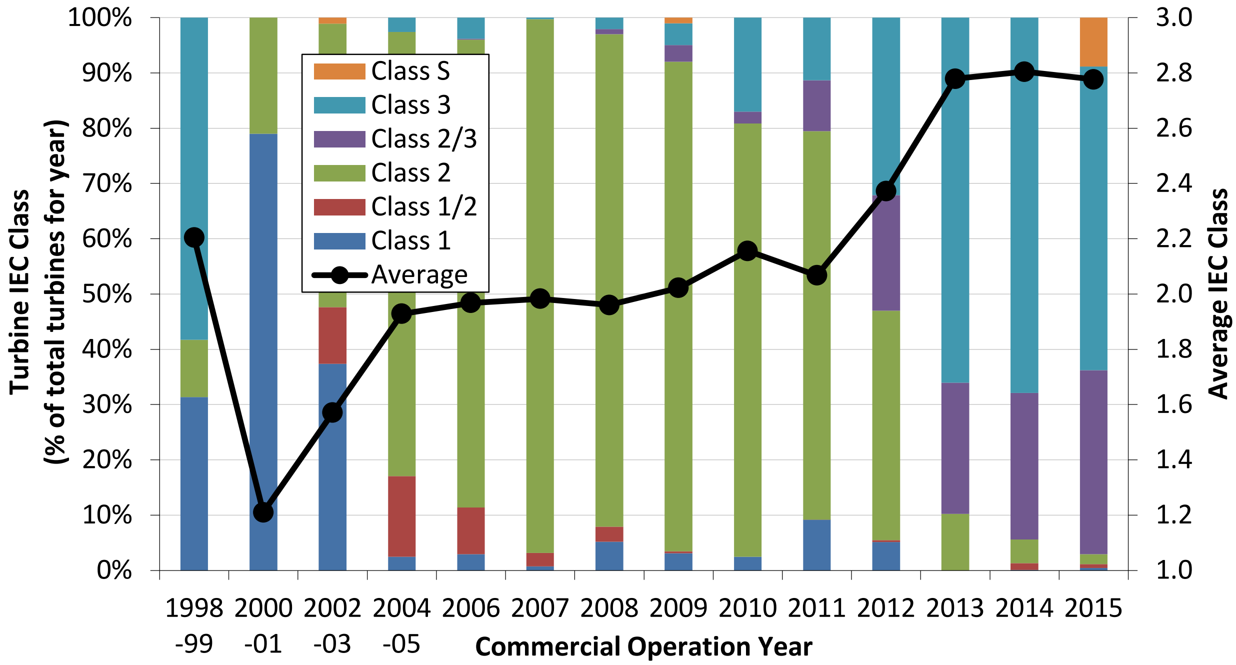
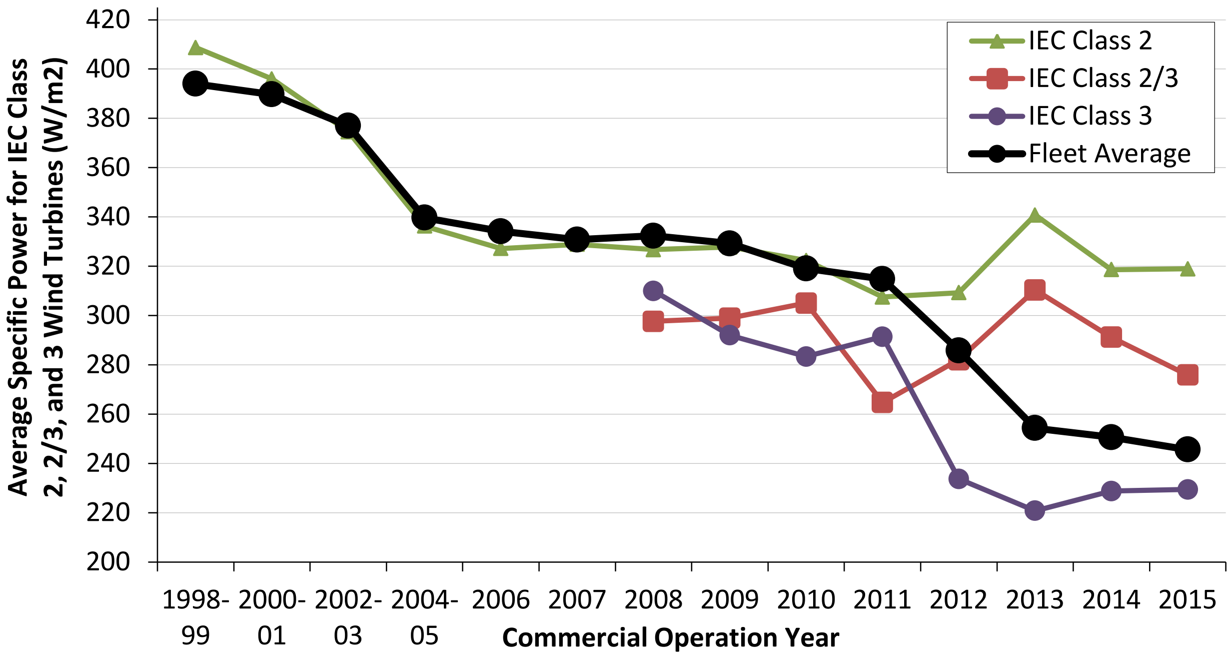


Figure 25. Trends in turbine IEC class

Moreover, Class 2, 2/3, and 3 turbine technology has not remained stagnant. Figure 26 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class, matching the average line shown in Figure 24) and also the average specific power ratings of Class 2, 2/3, and 3 (i.e., medium and lower wind speed) turbines installed in the United States. Through 2011, the progressively lower specific power of Class 2 turbines, which dominated the market, drove the overall decline in fleet-wide specific power. Since 2012, though, the continued drop in fleet-wide specific power has been driven by the penetration of the even-lower specific power of Class 3 and Class 2/3 machines. The overall trend in fleet-wide specific power has, therefore, been driven not only by the increased penetration of, initially, Class 2 and then, later, Class 2/3 and 3 turbines, but also by the progressively lower specific power ratings of turbines within each of these IEC classes.[35]

[35] The average specific power for the Class S turbines installed in 2015 was 205 W/m^2, which further drove down the fleet-wide average for specific power in 2015.



Note: specific power averages are shown only for years where there were at least 40 turbines in the respective IEC Class

Figure 26. Trends in specific power for IEC class 2, 2/3, and 3 turbines installed in the U.S.

Turbines originally designed for lower wind speeds are now regularly employed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast

One might expect that the increasing market share of turbines designed for lower wind speeds would be due to a movement by wind developers to deploy turbines in lower wind speed sites. Though there is some evidence of this movement historically (see Chapter 5), it is clear in Figures 27 and 28 that turbines originally designed for lower wind speeds are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites.

Figure 27 presents the percentage of turbines installed in four distinct regions of the United States[36] (see Figure 29 for regional definitions) that have one or more of the following three attributes: (a) a higher hub height, (b) a lower specific power, and (c) a higher IEC Class. It focuses solely on turbines installed in the 2012–2015 time period. Figure 28 presents similar information, but segments the data by the wind resource quality of the site rather than by the region in which the turbines are located.

[36] Due to very limited sample size, we exclude the Southeast region from these graphs and related discussion.

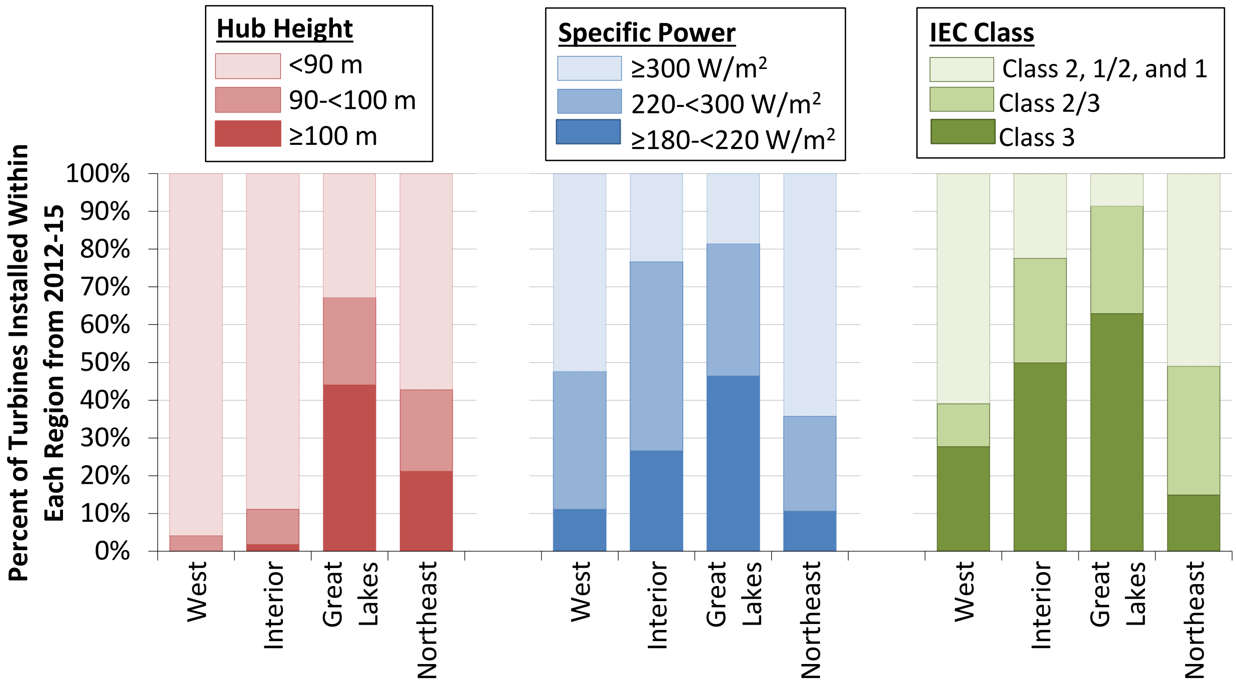
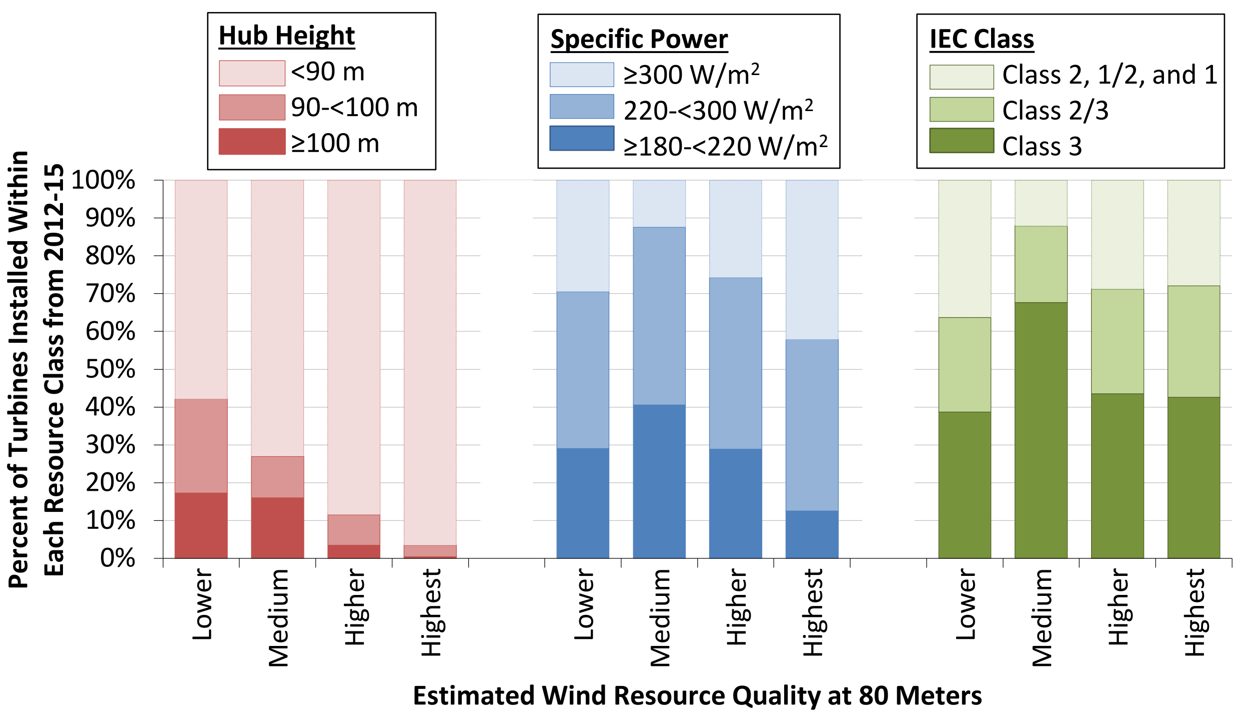


Figure 27. Deployment of turbines originally designed for lower wind speed sites, by region



Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The “lower” category includes all projects with an estimated gross capacity factor of <40%, the “medium” category corresponds to 40%–45%, the “higher” category corresponds to 45%-50%, and the “highest” category includes any project at or exceeding 50%.

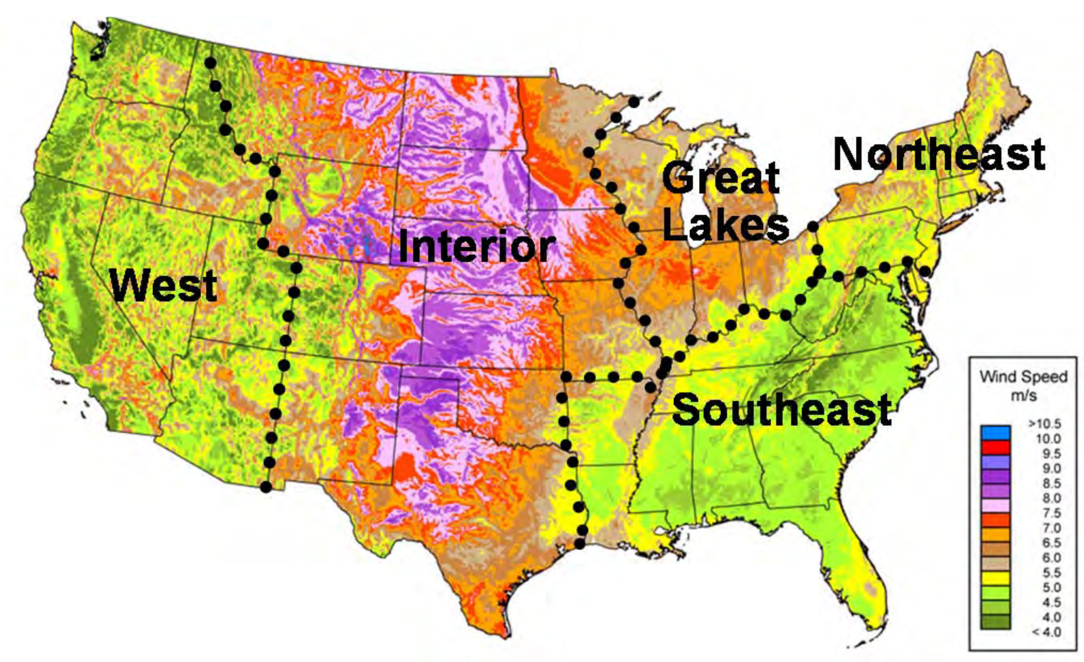
Figure 28. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality

Taller towers (i.e., 90 meters and above) have seen higher market share in the Great Lakes (67%) and Northeast (43%) than in the Interior (11%) and West (4%), often in sites with lower wind speeds. This is largely due to the fact that such towers are most commonly used in sites with higher-than-average wind shear (i.e., greater increases in wind speed with height) to access the better wind speeds that are typically higher up. Sites with higher wind shear are prevalent in the Great Lakes and Northeast.

Low specific power machines installed over this four-year period have been regularly deployed in all regions of the country, though their market share in the Great Lakes (81%) and Interior (77%) exceeds that in the West (48%) and Northeast (36%). Similarly, these turbines have been commonly used in all resource regimes including at sites with very high wind speeds, as shown in Figure 28. Turbines with the lowest specific power ratings (180–220 W/m^2), however, have been installed in greater proportions at lower, medium, and higher wind speed sites than at the highest wind speed sites, and are more prevalent in the Great Lakes.

Turning to IEC Class, we see a somewhat similar story. Over this period, Class 3 and Class 2/3 machines have had the largest market share in the Great Lakes (91%) and Interior (78%) regions, but have also gained significant market in the Northeast (49%) and West (39%). Moreover, these turbines have been regularly deployed in both lower- and higher-quality resources sites.

In combination, these findings demonstrate that low specific power and Class 3 and 2/3 turbines, originally designed for lower wind speed sites, have established a strong foothold across the nation and over a wide range of wind speeds. In many parts of the Interior region, in particular, relatively low wind turbulence has allowed turbines designed for low wind speeds to be deployed across a wide range of site-specific resource conditions.



Source: AWS Truepower, National Renewable Energy Laboratory

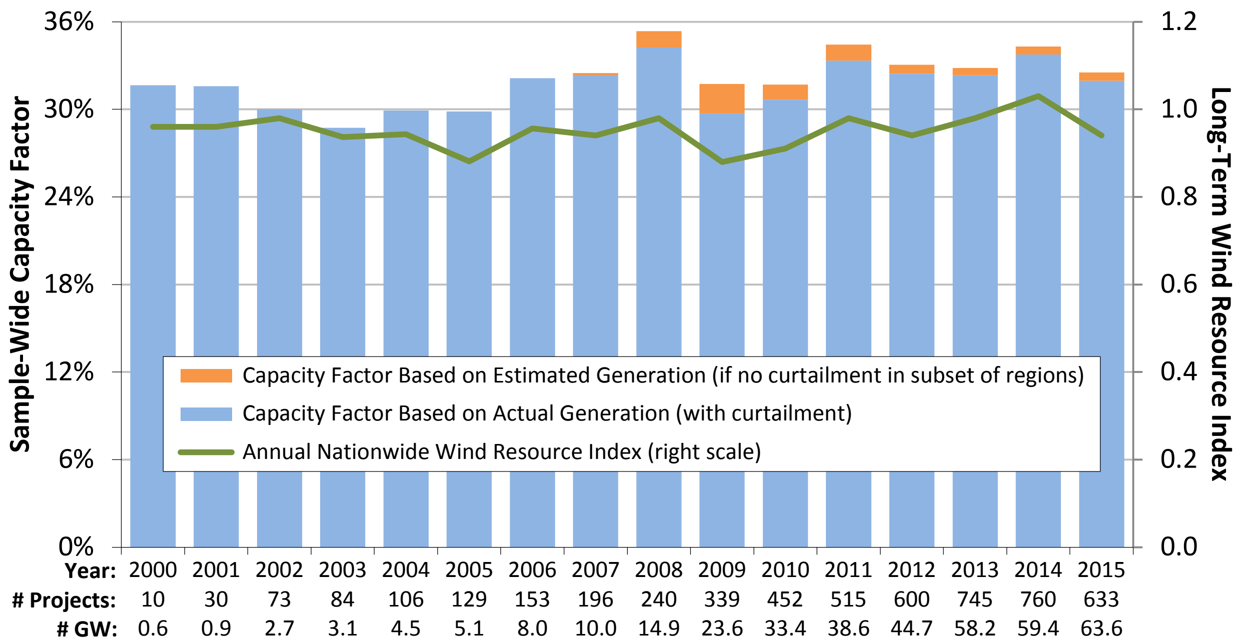
Figure 29. Regional boundaries overlaid on a map of average annual wind speed at 80 meters

5. Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a Berkeley Lab compilation of project-level capacity factors. The full data sample consists of 633 wind projects built between 1998 and 2014 totaling 63,556 MW (96.5% of nationwide installed wind capacity at the end of 2014).[37] Excluded from this assessment are older projects, installed prior to 1998. The discussion is divided into three subsections: the first analyzes trends in sample-wide capacity factors over time; the second looks at variations in capacity factors by project vintage; and the third focuses on regional variations. Unless otherwise noted, all capacity factors in this chapter are reported on a net (i.e., taking into account losses from curtailment, less-than-full availability, wake effects, icing and soiling, etc.) rather than gross basis.

Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability

The blue bars in Figure 30 show the average sample-wide capacity factor of wind projects in each calendar year among a progressively larger cumulative sample in each year, focusing on projects installed from 1998 through 2014.[38]



Source: Berkeley Lab

Figure 30. Average cumulative sample-wide capacity factors by calendar year

[37] Although some performance data for wind power projects installed in 2015 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2014.
[38] There are fewer individual projects—although more capacity—in the 2015 cumulative sample than there are in 2014. This is due to the sampling method used by EIA, which focuses on a subset of larger projects throughout the year, before eventually capturing the entire sample some months after the year has ended. As a result, it might be late 2016 before EIA reports 2015 performance data for all of the wind power projects that it tracks, and in the meantime this report is left with a smaller sample consisting mostly of the larger projects in each state.

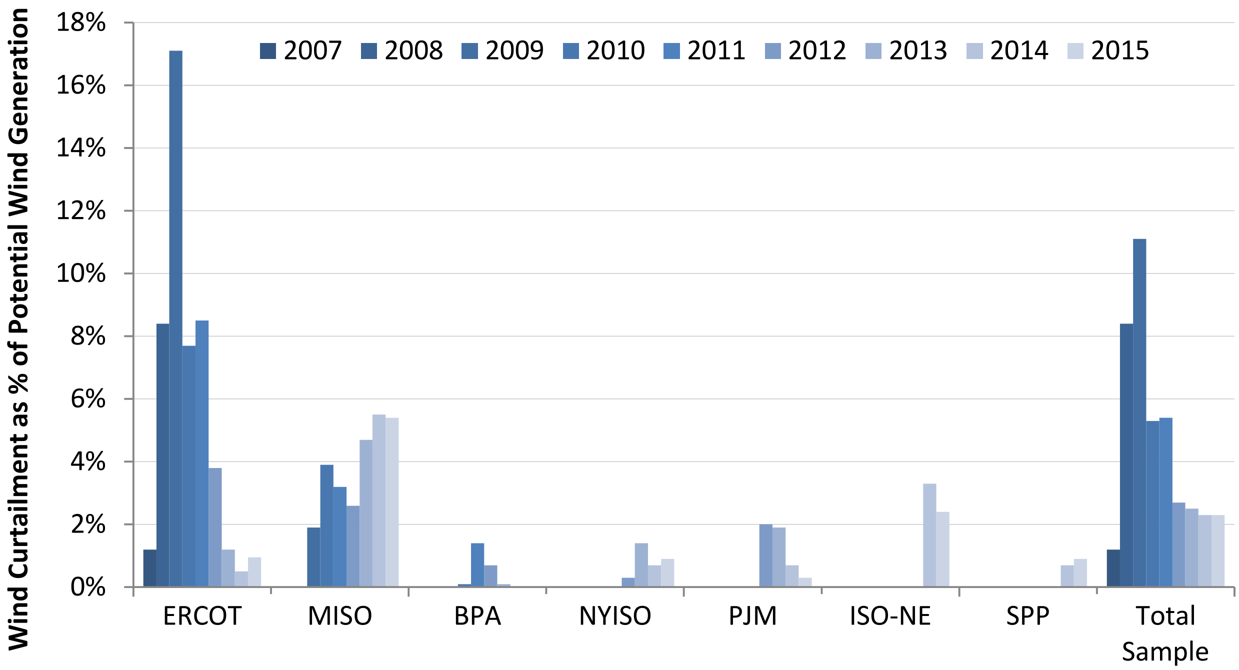
Viewed this way—on a cumulative, sample-wide basis—one might expect to see a gradual improvement in capacity factor over time, as newer turbines with taller towers and lower specific power are added to the fleet. In general, the data support this trend; capacity factors averaged 32.8% between 2011 and 2015 versus 31.8% between 2006 and 2010 versus 30.3% between 2000 and 2005. However, several factors influence the apparent strength of this time-based trend. Two of those factors are discussed below—wind energy curtailment and inter-year variability in the strength of the wind resource. Two additional factors—the average quality of the resource in which projects are located and performance degradation as projects age—are discussed in the next section.

Wind Power Curtailment. Curtailment of wind project output can occur due to transmission inadequacy, minimum generation limits, other forms of grid inflexibility, and/or environmental restrictions—all but the last of which could help to push local wholesale power prices negative, thereby potentially triggering curtailment for economic reasons, particularly among wind projects that do not receive the PTC. Curtailment might be expected to increase as wind energy penetrations rise. That said, in areas where curtailment has been particularly problematic in the past—principally in Texas—steps taken to address the issue have significantly mitigated the concern. For example, Figure 31 shows that only 1.0% of potential wind energy generation within ERCOT was curtailed in 2015, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. Primary causes for the decrease were the Competitive Renewable Energy Zone transmission line upgrades, most of which were completed by the end of 2013, and a move to more-efficient wholesale electric market designs.

Elsewhere, the only regions shown in Figure 31 in which wind curtailment exceeded 1% in 2015 were MISO at 5.4% (as much of the new wind buildout continues to be located within this ISO) and ISO-NE at 2.4% (a rough estimate that the grid operator suspects is understated). Except for BPA, all of the regions shown in Figure 31 track both “forced” (i.e., required by the grid operator for reliability reasons) and “economic” (i.e., voluntary as a result of wholesale market prices) curtailment. BPA (which did not report in 2014 or 2015) tracks only forced curtailment, which means that its modest curtailment estimates for 2010–2013 may understate the true level of curtailment experienced by wind power projects in the region.

In aggregate, assuming a 33% average capacity factor, the total amount of curtailed wind generation tracked in Figure 31 for 2015 equates to the annual output of roughly 1,125 MW of wind power capacity. Looked at another way, wind power curtailment has reduced sample-wide average capacity factors in recent years. While the blue bars in Figure 30 reflect actual capacity factors—i.e., including the negative impact of curtailment events—the orange bars add back in the estimated amount of wind generation that has been forced to curtail in recent years within the seven areas shown in Figure 31, to estimate what the sample-wide capacity factors would have been absent this curtailment. As shown, sample-wide capacity factors would have been on the order of 0.5–2 percentage points higher nationwide from 2008 through 2015 absent curtailment in just this subset of regions. Estimated capacity factors would have been even higher if comprehensive forced and economic curtailment data were available for all regions.[39]

[39] Excluding BPA (for which 2015 data were not available), the six regions included in Figure 31 collectively contributed 72% of total U.S. wind generation in 2015.



Note: BPA's 2014 and 2015 curtailment estimates were unavailable at the time of publication. A portion of BPA's curtailment from 2010-13 is estimated assuming that each curtailment event lasts for half of the maximum possible hour for each event. SPP's 2014 curtailment estimate is for March through December only. PJM's 2012 curtailment estimate is for June through December only. Except for BPA, which tracks only forced curtailment, all other percentages shown in the figure represent both forced and economic curtailment.

Source: ERCOT, MISO, BPA, NYISO, PJM, ISO-NE, SPP

Figure 31. Estimated wind curtailment by region as a percentage of potential wind generation

Inter-Year Wind Resource Variability. The strength of the wind resource varies from year to year, partly in response to significant persistent weather patterns such as El Niño/La Niña. A relatively strong El Niño had a significant impact in the first two quarters of 2015, contributing to wind speeds that were significantly below normal throughout much of the U.S. Although wind speeds recovered in the third and fourth quarters, annual average deviations of 6% or more for all of 2015 were common, particularly in the West and southern Great Plains states, where much of the wind capacity in the U.S. is located (AWS Truepower 2016).

The green line in Figure 30 also shows that 2015 was generally a bad wind year, at least in terms of the national average wind energy resource as measured by one large project sponsor.[40] It is also evident from the figure that movements in sample-wide capacity factor from year to year are influenced by the natural inter-year variability in the strength of the national wind resource.

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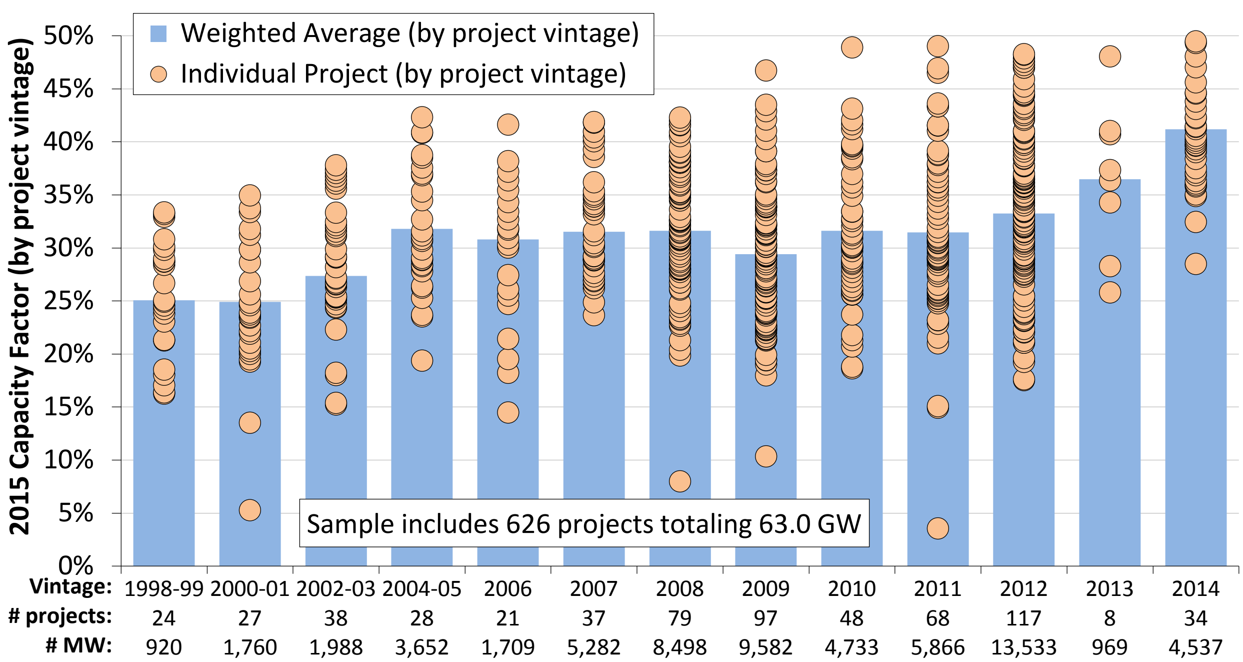
[40] The green line in Figure 30 estimates changes in the strength of the average nationwide wind resource from year to year and is derived from data presented by NextEra Energy Resources in its quarterly earnings reports.

The impact of technology trends on capacity factor becomes more apparent when parsed by project vintage

One way to partially control for the time-varying influences described in the previous section (e.g., annual wind resource variations or changes in the amount of wind curtailment) is to focus exclusively on capacity factors in a single year, such as 2015.[41] As such, while Figure 30 presents sample-wide capacity factors in each calendar year, Figure 32 instead shows only capacity factors in 2015, broken out by project vintage. Wind power projects built in 2015 are again excluded, as full-year performance data are not yet available for those projects.

Figure 32 shows an increase in weighted-average 2015 capacity factors when moving from projects installed in the 1998–1999 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011, however, show little if any improvement in average capacity factors recorded in 2015. This pattern of stagnation is finally broken by projects installed in 2012, and even more so by 2013- and 2014-vintage projects. The average 2015 capacity factor among projects built in 2014 reached 41.2%, compared to an average of 31.2% among all projects built from 2004–2011, and 25.8% among all projects built from 1998–2003.



Source: Berkeley Lab

Figure 32. Calendar year 2015 capacity factors by project vintage

The trends in average capacity factor by project vintage seen in Figure 32 can largely be explained by three underlying influences shown in Figure 33: a trend towards progressively lower specific power ratings (note that Figure 33 actually shows the inverse of specific power, so

[41] Although focusing just on 2015 does control (at least loosely) for some of these known time-varying impacts, it also means that the *absolute* capacity factors shown in Figure 32 may not be representative over longer terms if 2015 was not a representative year in terms of the strength of the wind resource (as mentioned above, it was not – wind speeds were well below normal across much of the U.S. in 2015) or wind power curtailment.

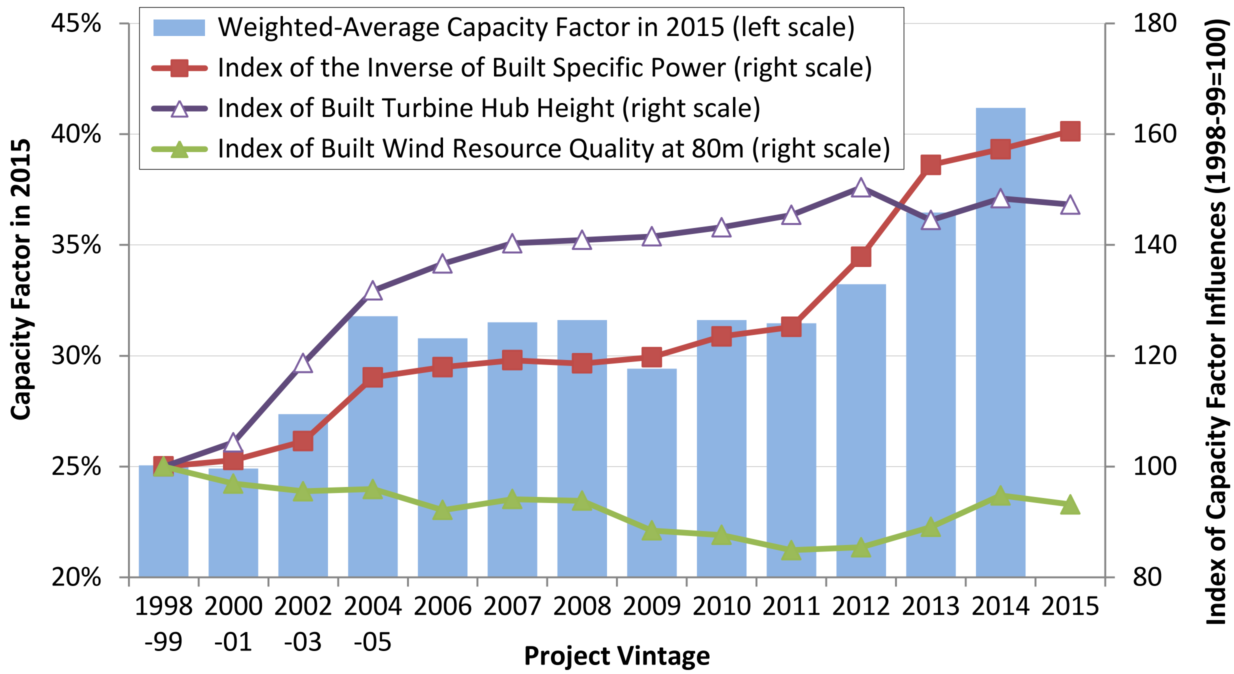
that a declining specific power is correlated directionally with a higher capacity factor) and higher hub heights—both of which should boost capacity factors, all else equal—as well as a progressive build-out of lower-quality wind resource sites through 2012 (which should hurt capacity factors, all else equal), followed by deployment at more energetic sites in 2013 and 2014. In addition, as shown later in Figure 36, project vintage itself could be a fourth driver, given the possible degradation in performance among older projects.

The first two of these influences—the decline in average “specific power” (i.e., W/m^2 of rotor swept area) and the increase in average hub height among more recent turbine vintages—have already been well-documented in Chapter 4, but are shown yet again in Figure 33 (again, with specific power shown in inverse form, to correlate with capacity factor movements) in index form, relative to projects built in 1998-99. All else equal, a lower average specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity, meaning that the generator is likely to run closer to or at its rated capacity more often. Meanwhile, at sites with positive wind shear, increasing turbine hub heights can help the rotor to access higher wind speeds.

Counterbalancing the decline in specific power and the increase in hub height, however, has been a tendency to build new wind projects in lower-quality wind resource areas,[42] at least through 2012—and especially among projects installed from 2009 through 2012[43]—as shown by the wind resource quality index in Figure 33. This trend reversed course in 2013 and even more so in 2014, as deployment increasingly shifted to the Interior region.

[42] Estimates of wind resource quality are based on site estimates of *gross* capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. We index the values to those projects built in 1998-99. Further details are found in the Appendix.

[43] Several factors could have driven this trend, especially in the 2009 to 2012 period. First, the increased availability of low-wind-speed turbines that feature higher hub heights and a lower specific power may have enabled the economic build-out of lower-wind-speed sites. Second, developers may have reacted to increasing transmission constraints over this period (or other siting constraints, or even just regionally differentiated wholesale electricity prices) by focusing on those projects in their pipeline that may not be located in the best wind resource areas but that do have access to transmission (or higher-priced markets, or readily available sites without long permitting times). Finally, federal and/or state policy could be partly responsible. For example, wind projects built in the 4-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers seized this limited opportunity to build out the less-energetic sites in their development pipelines. Additionally, state RPS requirements sometimes require or motivate in-state or in-region wind development in lower wind resource regimes.



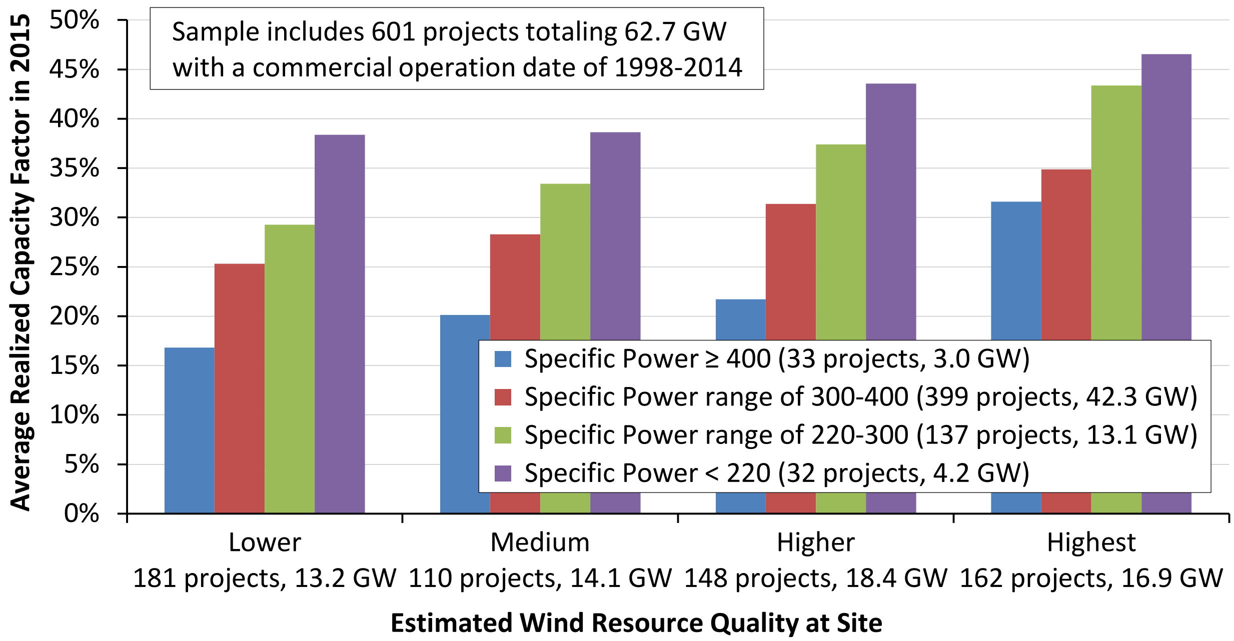
Note: In order to have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

Source: Berkeley Lab

Figure 33. 2015 capacity factors and various drivers by project vintage

In Figure 33, the significant improvement in average 2015 capacity factors from those projects built in 1998-2001 to those built in 2004-2005 is driven by both an increase in hub height and a decline in specific power, and despite a shift towards somewhat-lower-quality wind resource sites. The stagnation in average capacity factor that subsequently persisted through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. Finally, capacity factors began to move higher among 2012-vintage projects, and continued even higher among 2013- and 2014-vintage projects, driven by a sharp reduction in average specific power coupled with a marked improvement in the quality of wind resource sites (average hub height stayed relatively constant over this period). Looking ahead to 2016, 2015-vintage projects are likely to perform similarly to those built in 2014 on average, given only modest changes in these three underlying drivers among the 2015 fleet.

To help disentangle the competing influences of turbine design evolution and lower wind resource quality on capacity factor, Figure 34 controls for each. Across the x-axis, projects are grouped into four different categories, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As one would expect, projects sited in higher wind speed areas generally realized higher 2015 capacity factors than those in lower wind speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range realized significantly higher 2015 capacity factors than those in a higher specific power range.



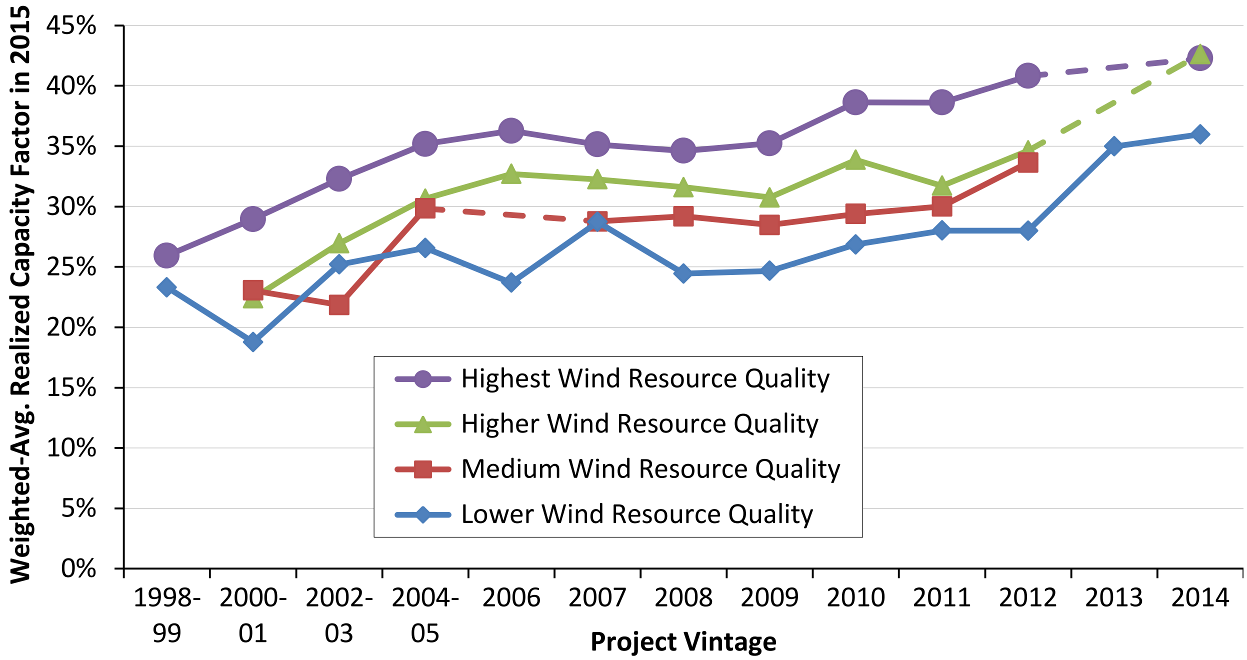
Note: Wind resource quality is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. The "lower" category includes all projects with an estimated gross capacity factor of <40%, the "medium" category corresponds to 40%–45%, the "higher" category corresponds to 45%-50%, and the "highest" category includes any project at or exceeding 50%.

Source: Berkeley Lab

Figure 34. Calendar year 2015 capacity factors by wind resource quality and specific power

As a result, it is clear that turbine design changes (specifically, lower specific power, but also, to a lesser extent, higher hub heights) are driving realized capacity factors higher among projects located within a given wind resource regime. This finding is further illustrated in Figure 35, which again groups projects into the same four different categories of wind resource quality, and then reports average realized 2015 capacity factors by commercial operation date within each category.[44] As before, projects sited in higher wind speed areas have, on average, higher capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been an improvement in capacity factors over time, by commercial operation date.

[44] The figure only includes those data points representing at least three projects in any single resource-year pair. Among 2013-vintage projects, only the "lower" wind resource quality grouping meets this sample size threshold. In addition, the "medium" wind resource quality grouping lacks sufficient sample size in both 2006 and 2014. In years where insufficient sample size prohibits the inclusion of a data point, dashed lines are used to interpolate from the prior year to the subsequent year.

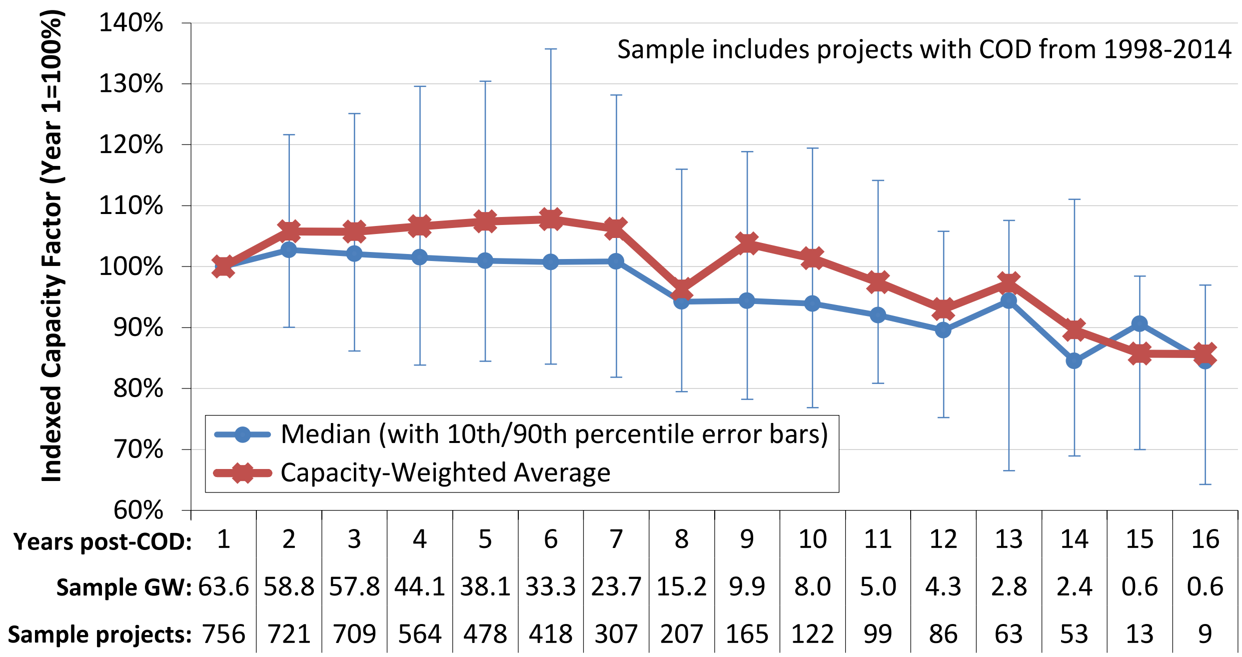


Source: Berkeley Lab

Figure 35. Calendar year 2015 capacity factors by project vintage and wind resource quality

One final variable that could be influencing the apparent improvement in 2015 capacity factors among more recent project vintages is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998-2001—may have performed worse than more recent vintages in 2015 simply due to their relative age. Figure 36 explores this question by graphing both median (with 10th and 90th percentile bars) and capacity-weighted average capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).

Figure 36 suggests some amount of performance degradation, particularly once projects age beyond 7-10 years—i.e., a period that roughly corresponds to the initial warranty period, as well as the PTC period. Such degradation among older projects could help to partially explain why, for example, in Figure 30 the sample-wide capacity factors in 2000 and 2001 exceeded 30%, while in Figure 32 the 1998-2001 project vintages (i.e., consisting of essentially the same set of projects) posted average capacity factors of just 25% in 2015.



Source: Berkeley Lab

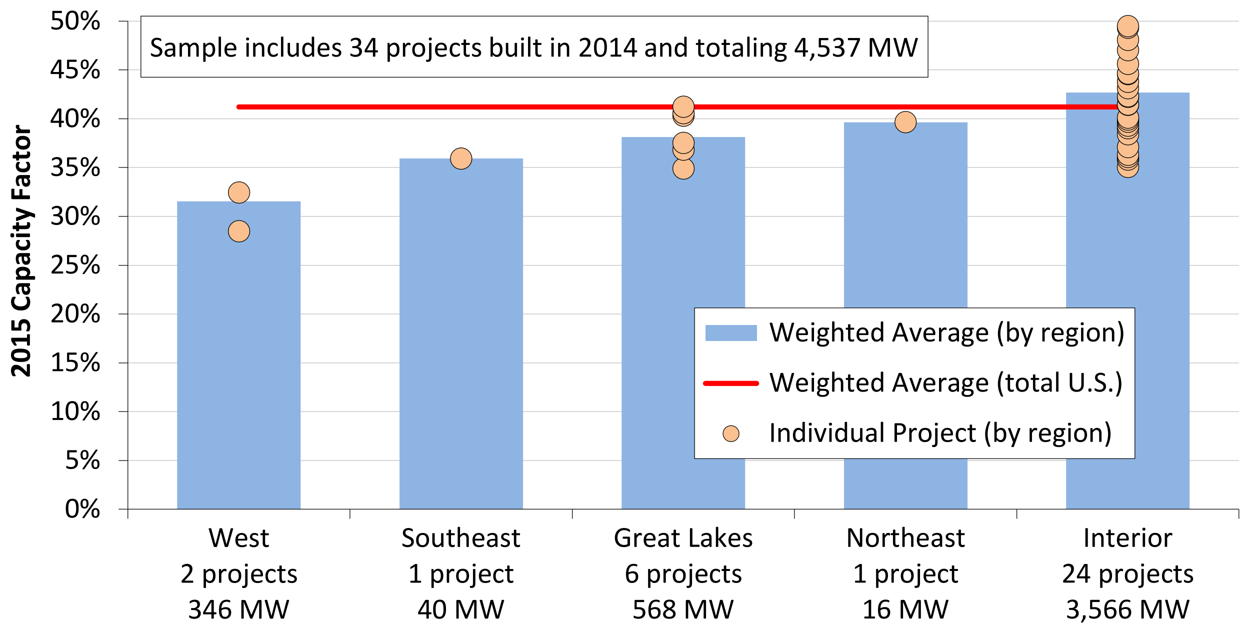
Figure 36. Post-COD changes in capacity factors over time suggest performance degradation

The median values in Figure 36 regularly fall below the capacity-weighted average values, suggesting that smaller projects tend to degrade more, and more rapidly, than larger projects. This difference could perhaps be attributable to less-stringent or -responsive O&M protocols among smaller projects. The PTC could be another influence, if smaller projects have instead more commonly opted for the ITC or its cash counterpart, the Section 1603 grant—neither of which depends on performance. Finally, the up-tick in year two for both the median and capacity-weighted average values could partly reflect the initial production ramp-up period that is commonly experienced by wind projects as they work through and resolve initial "teething" issues during their first year of operations.

Although all of these suppositions surrounding Figure 36 are intriguing and worthy of further study, a number of caveats are in order. First, no attempt was made to correct for inter-year variation in the strength of the wind resource. Although the potential impact of this omission is likely muted by the fact that year five (for example) for one project will be a different calendar year than year five for another project, inter-year resource variation could still play a role. Second, the sample is not the same in each year. The sample shrinks as the number of post-COD years increases, and is increasingly dominated by older projects using older turbine technology that may not be representative of today's turbines. Third, as with all figures presented in this chapter, turbine decommissioning is accounted for by adjusting the nameplate project capacity as appropriate over time (all the way to zero if a project is fully decommissioned), such that each figure, including Figure 36, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity.

Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology

The project-level spread in capacity factors shown in Figure 32 is enormous, with 2015 capacity factors ranging from a minimum of 28.5% to a maximum of 49.5% among those projects built in 2014 (this spread is even wider for projects built in earlier years). Some of the spread in project-level capacity factors—for projects built in 2014 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 37 shows the regional variation in 2015 capacity factors (using the regional definitions shown in Figure 29, earlier) based on just the sample of wind power projects built in 2014.



Source: Berkeley Lab

Figure 37. Calendar year 2015 capacity factors by region: 2014 vintage projects only

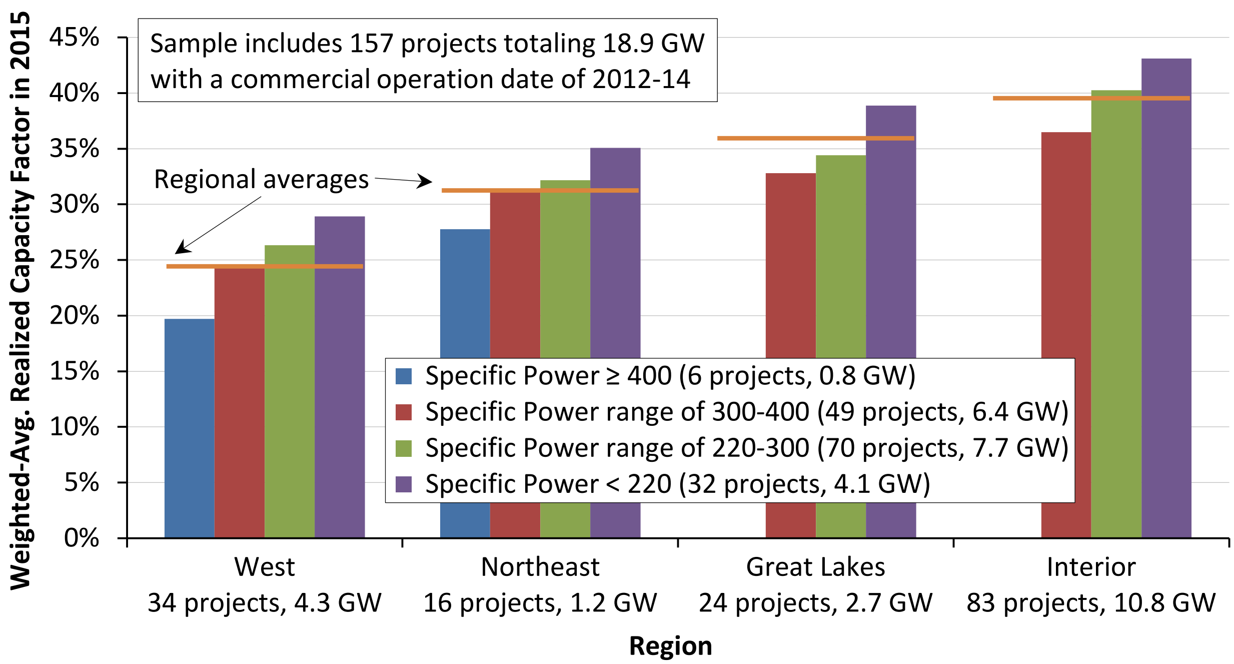
Although four of the five regions have a very limited sample (attributable to the fact that nearly 80% of the total capacity installed in 2014 was located in the Interior region), focusing only on this most recent vintage of projects is nevertheless appropriate in light of the significant disparity in average 2015 capacity factors among 2014 projects versus earlier vintages (see Figures 32 or 33). In other words, were Figure 37 to include vintages prior to 2014 in an effort to boost sample size, the stark differences in 2015 capacity factor across vintages could partially mask any regional differences. Focusing on just the two regions that include more than two projects in Figure 37, generation-weighted average capacity factors are the highest in the Interior region (42.7%) and a bit lower in the Great Lakes (38.1%).[45] Even within these regions, however, there

[45] Given the relatively small sample size in many regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2015, care should be taken in extrapolating these results. For example, many projects (of various vintages) located in Wyoming and Idaho – both states that faced significantly below-normal wind speeds in 2015 (AWS Truepower 2016) – experienced 2015 capacity factors that were as much as 8 to 9 percentage points below normal, while at the

can still be considerable spread—e.g., 2015 capacity factors range from 35% up to 49.5% among projects installed in the Interior region in 2014.

Some of this intra-regional variation can be explained by turbine technology. Figure 38 also provides a regional breakdown, although in this case it includes projects built from 2012-2014, which are further differentiated by average specific power. Including older vintages in Figure 38 is both more necessary (i.e., in order to have sufficient sample within each region to enable a specific power breakout) and less problematic (i.e., given that Figure 38 controls for the impact of specific power) than it would have been for Figure 37.

As one would expect, within each of the four regions along the x-axis, projects using turbines that fall into a lower specific power range generally have higher realized capacity factors than those in a higher specific power range.



Source: Berkeley Lab

Figure 38. Calendar year 2015 capacity factors by region and specific power

As shown earlier in Chapter 4 ("Technology Trends"), the rate of adoption of turbines with lower specific power ratings has varied by region. For example, Figure 27 (earlier) shows that 46% of all turbines installed in the Great Lakes region from 2012–2015 have a specific power rating of less than 220 W/m^2, while the comparable number in the West is 11%. Similarly, 67% of all turbines installed in the Great Lakes region from 2012–2015 have tower heights of at least 90 meters, compared to 4% in the West. The relative degree to which these regions have embraced these turbine design enhancements influences, to some extent, their ranking in Figures 37 and 38.

other extreme many projects in Minnesota, Wisconsin, and Michigan – states that were largely spared the weak winds of 2015 (AWS Truepower 2016) – reported higher-than-normal capacity factors in 2015.

Taken together, Figures 30–38 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.

6. Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally O&M costs. Sample size varies among these different datasets, and is therefore discussed within each section of this chapter.

Wind turbine prices remained well below levels seen several years ago

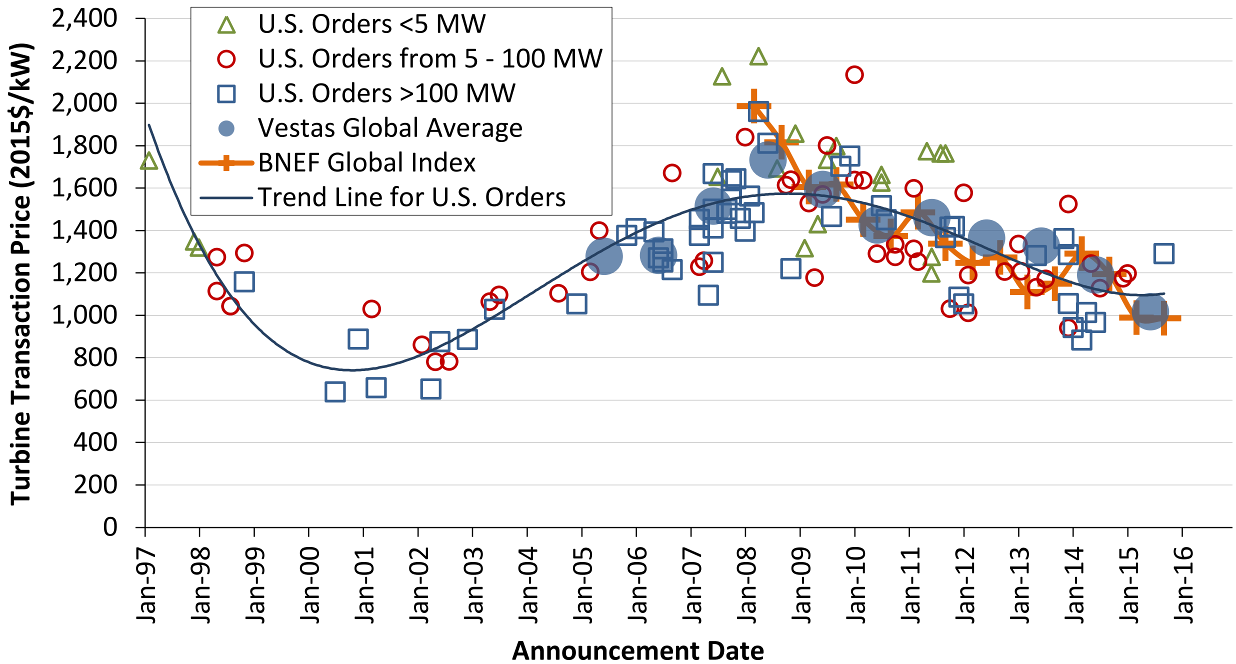
Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Prices maintained their low levels in 2015, aided in part by the strength of the U.S. dollar.

Berkeley Lab has gathered price data for 121 U.S. wind turbine transactions totaling 30,480 MW announced from 1997 through 2015, but this sample includes only nine transactions (1,460 MW) announced in 2014 or 2015. Sources of turbine price data vary, including SEC and other regulatory filings, as well as press releases and news reports. Most of the transactions included in the Berkeley Lab dataset include turbines, towers, delivery to site, and limited warranty and service agreements.[46] Nonetheless, wind turbine transactions differ in the services included (e.g., whether towers and installation are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices.

Unfortunately, collecting data on U.S. wind turbine transaction prices is a challenge, in that only a fraction of the announced turbine transactions have publicly revealed pricing data. Partly as a result, Figure 39—which depicts these U.S. wind turbine transaction prices—also presents data from two other sources: (1) Vestas on that company's global average turbine pricing from 2005 through 2015, as reported in Vestas' financial reports; and (2) Bloomberg NEF (2016a) on that company's global average turbine price index by contract signing date.

After hitting a low of roughly $750/kW from 2000 to 2002, average wind turbine prices increased by approximately $800/kW (more than 100%) through 2008, rising to an average of more than $1,500/kW. The increase in turbine prices over this period was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter (Bolinger and Wiser 2011).

[46] Because of data limitations, the precise content of many of the individual transactions is not known.



Source: Berkeley Lab

Figure 39. Reported wind turbine transaction prices over time

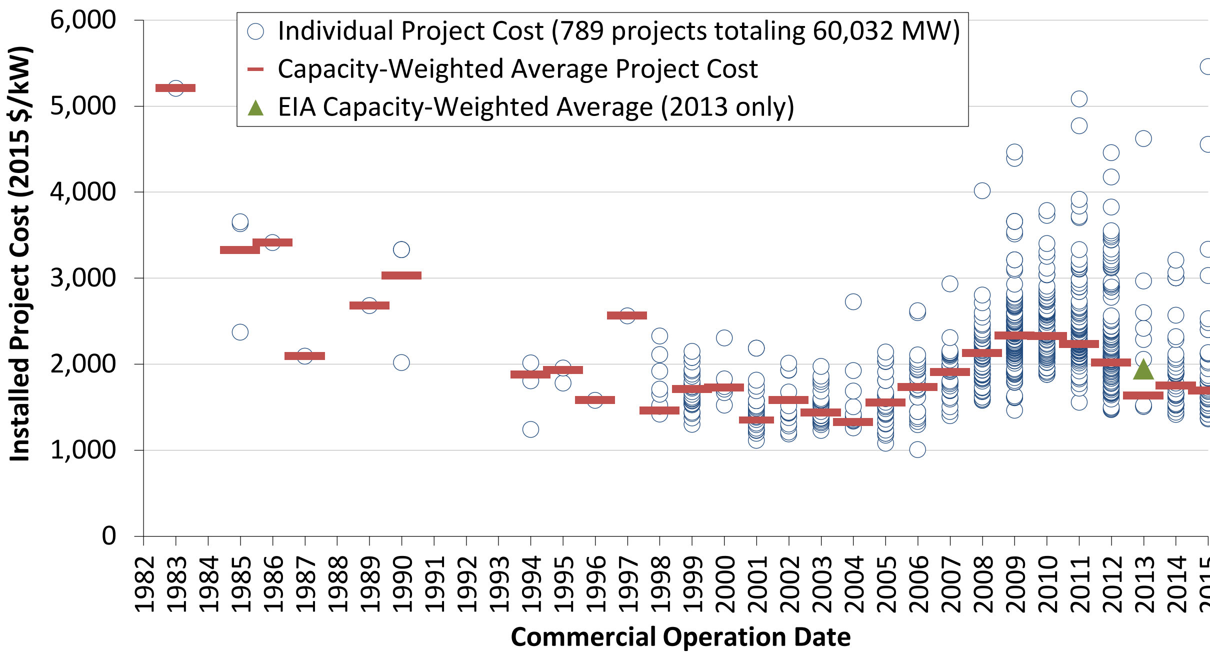
Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 39, our limited sample of recently announced U.S. turbine transactions shows pricing in the $850–$1,250/kW range. Bloomberg NEF (2016b) reports average pricing for recent North American contracts of roughly $1,000/kW. Data from Vestas confirm these pricing points, with average global sales prices in 2015 of $1,020/kW, when denominated in U.S. dollars.

Overall, these figures suggest price declines of 20%–40% since late 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and more favorable terms for turbine purchasers (e.g., reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial O&M contract durations, improved warranty terms, and more-stringent performance guarantees). These price reductions and improved terms have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights are improving capacity factors and further reducing wind power prices.

Lower turbine prices have driven reductions in reported installed project costs

Berkeley Lab also compiles data on the total installed cost of wind power projects in the United States, including data on 44 projects completed in 2015 totaling 5,772 MW, or 67% of the wind power capacity installed in that year. In aggregate, the dataset (through 2015) includes 789 completed wind power projects in the continental United States totaling 60,032 MW and equaling roughly 81% of all wind power capacity installed in the United States at the end of 2015. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.

As shown in Figure 40, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010, with substantial declines since that time. That changes in average installed project costs would lag behind changes in average turbine prices is not surprising and reflects the normal passage of time between when a turbine supply agreement is signed (the time stamp for Figure 39) and when those turbines are actually installed and commissioned (the time stamp for Figure 40).[47]



Source: Berkeley Lab (some data points suppressed to protect confidentiality), Energy Information Administration

Figure 40. Installed wind power project costs over time

In 2015, the capacity-weighted average installed project cost within our sample stood at roughly $1,690/kW, down $640/kW or 27% from the apparent peak in average reported costs in 2009 and 2010. Early indications from a limited sample of 18 projects (totaling 3.4 GW) currently under construction and anticipating completion in 2016 suggest no material change in capacity-weighted average installed costs in 2016.[48]

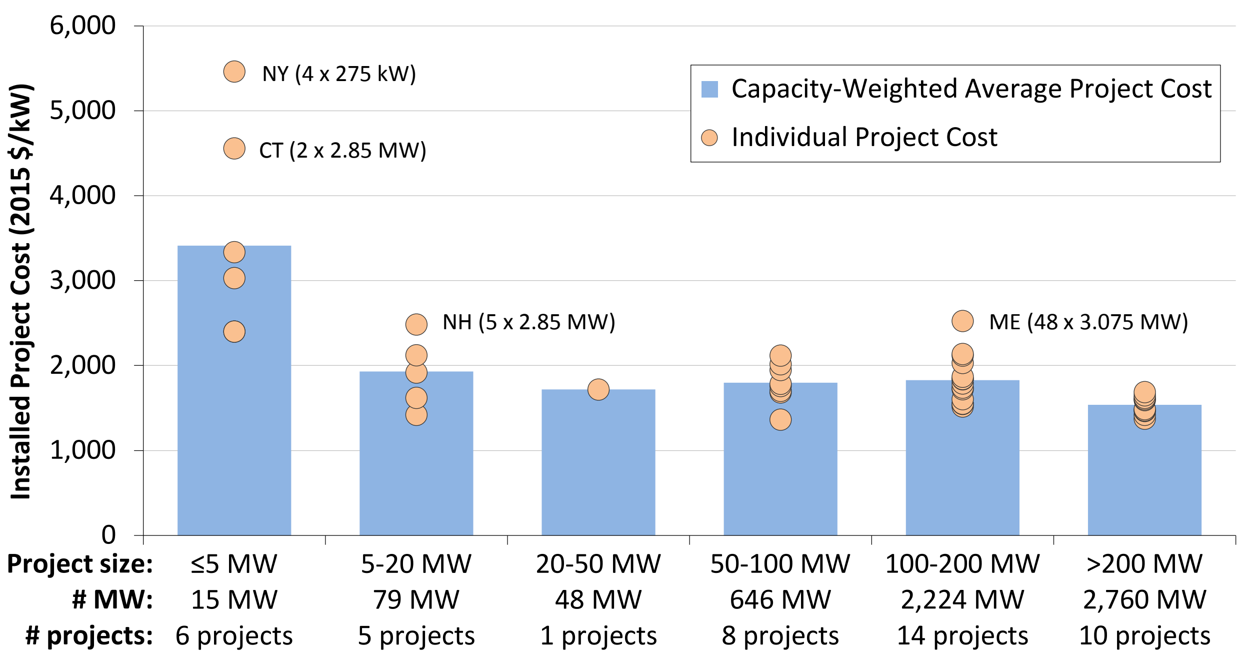
[47] For projects placed in service from 2009 through 2012, Figure 40 partly reflects installed cost estimates derived from publicly available data from the Section 1603 cash grant program. In some cases (although exactly which are unknown), the Section 1603 grant data likely reflect the fair market value rather than the installed cost of wind power projects; in such cases, the installed cost estimates shown in Figure 40 will be artificially inflated.

[48] Learning curves have been used extensively to understand past cost trends and to forecast future cost reductions for a variety of energy technologies, including wind energy. Learning curves start with the premise that increases in the cumulative production or installation of a given technology lead to a reduction in its costs. The principal

Also included in Figure 40 is a single weighted-average data point for 2013 from the EIA, which has recently begun to collect installed cost data through its Form 860 survey instrument. Although the EIA's capacity-weighted average cost for 2013 is higher than that derived from our sample (which is perhaps skewed to the low side by one sizable project in a year when little capacity was built), it is nevertheless aligned with the declining cost trend from 2009 to 2015. The EIA plans to report average data for 2014 and 2015 later in 2016; we will include these additional data points in future editions of this report.

Installed costs differed by project size, turbine size, and region

Average installed project costs exhibit economies of scale, especially at the lower end of the project size range. Figure 41 shows that among the sample of projects installed in 2015, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 5–20 MW range. As project size increases further, however, economies of scale appear to be somewhat less prevalent. A few notable high-cost projects are called out in Figure 41; all are from the high-cost Northeast region, with the two highest-cost projects either using sub-MW turbines (NY) or representing the first utility-scale wind installation in a state (CT).[49]



Source: Berkeley Lab

Figure 41. Installed wind power project costs by project size: 2015 projects

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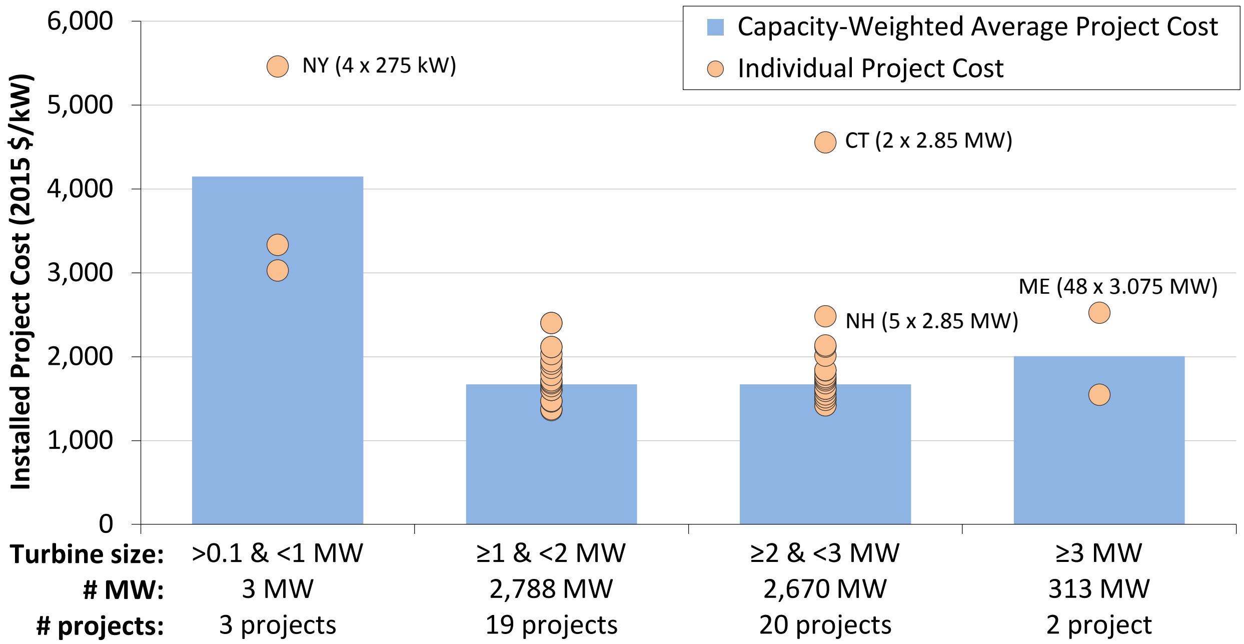
parameter calculated by learning curve studies is the learning rate: for every doubling of cumulative production/installation, the learning rate specifies the associated percentage reduction in costs. Considering the full time series of installed cost data presented in Figure 40 (from 1982 through 2015) in conjunction with global cumulative wind power installations over that same period results in a learning rate of 6.5%.

[49] The relatively high $/kW cost of the Connecticut project is also partly due to the fact that the project's nameplate capacity—which serves as the denominator of the $/kW cost estimate—is capped at 5 MW, even though the two 2.85 MW turbines are capable of generating a total of 5.7 MW. If $/kW costs were based on 5.7 MW rather than 5 MW, the cost of this project would be $3,995/kW rather than $4,554/kW.

Another way to look for economies of scale is by turbine size (rather than by project size), on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines as opposed to more, smaller turbines. Figure 42 explores this relationship and illustrates that here too some economies of scale are evident as turbine size increases—particularly moving from sub-MW turbines to MW class turbines.[50] The same apparent high-cost projects are noted in Figure 42, with the Connecticut project seemingly more of an outlier in this case, viewed within the context of turbine capacity rather than project capacity.



Source: Berkeley Lab

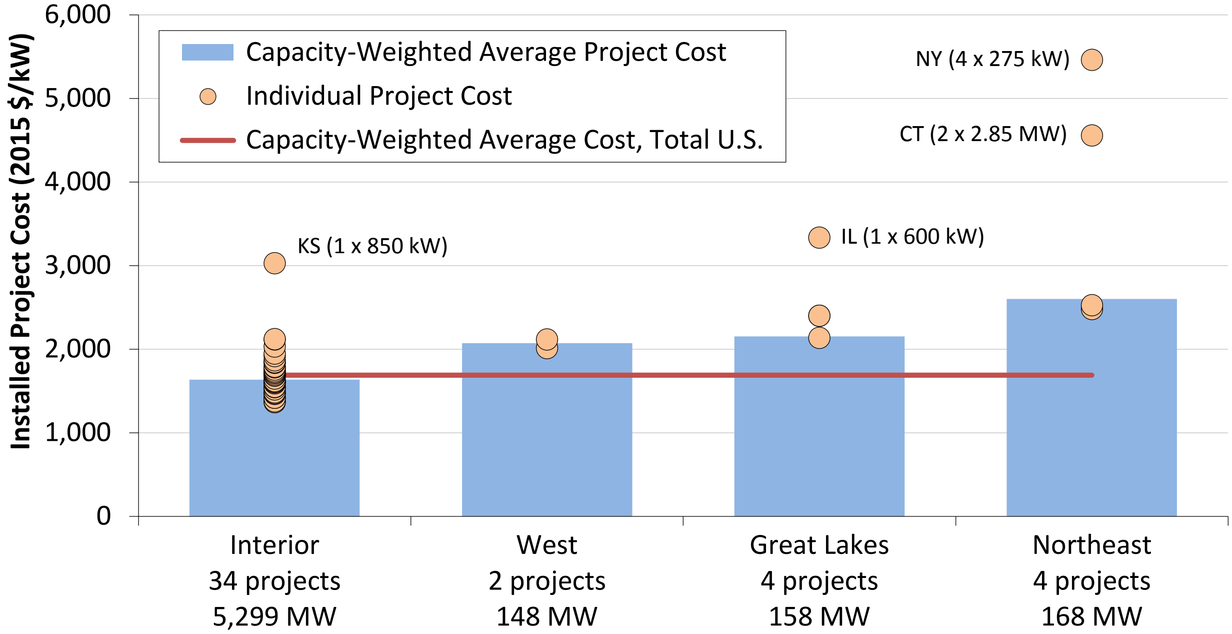
Figure 42. Installed wind power project costs by turbine size: 2015 projects

Regional differences in average project costs are also apparent and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2015, Figure 43 breaks out project costs among four of the five regions defined in Figure 29 (there were no projects built in the Southeast region in 2015).[51] The Interior region—with by far the largest sample—was the lowest-cost region on average, with an average cost of $1,640/kW, while the Northeast was the

[50] There is likely some correlation between turbine size and project size, at least at the low end of the range of each. In other words, projects of 5 MW or less are more likely than larger projects to use individual turbines of less than 1 MW. As such, Figures 41 and 42—both of which show scale economies at small project or turbine sizes, diminishing as project or turbine size increases—could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.

[51] For reference, the 73,992 MW of wind installed in the United States at the end of 2015 is apportioned among the five regions shown in Figure 29 as follows: Interior (63%), West (19%), Great Lakes (11%), Northeast (6%), and Southeast (1%). The remaining installed U.S. wind power capacity is located in Hawaii, Alaska, and Puerto Rico and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

highest-cost region (although with a sample of just four projects, two of which stand out as unusually high-cost projects).[52] Viewed within this regional context, the Maine and New Hampshire projects identified as high-cost in Figures 41 and 42 no longer appear as such in Figure 43, while two new single-turbine projects involving sub-MW turbines in the Interior and Great Lakes regions now stand out as high-cost projects for the first time.

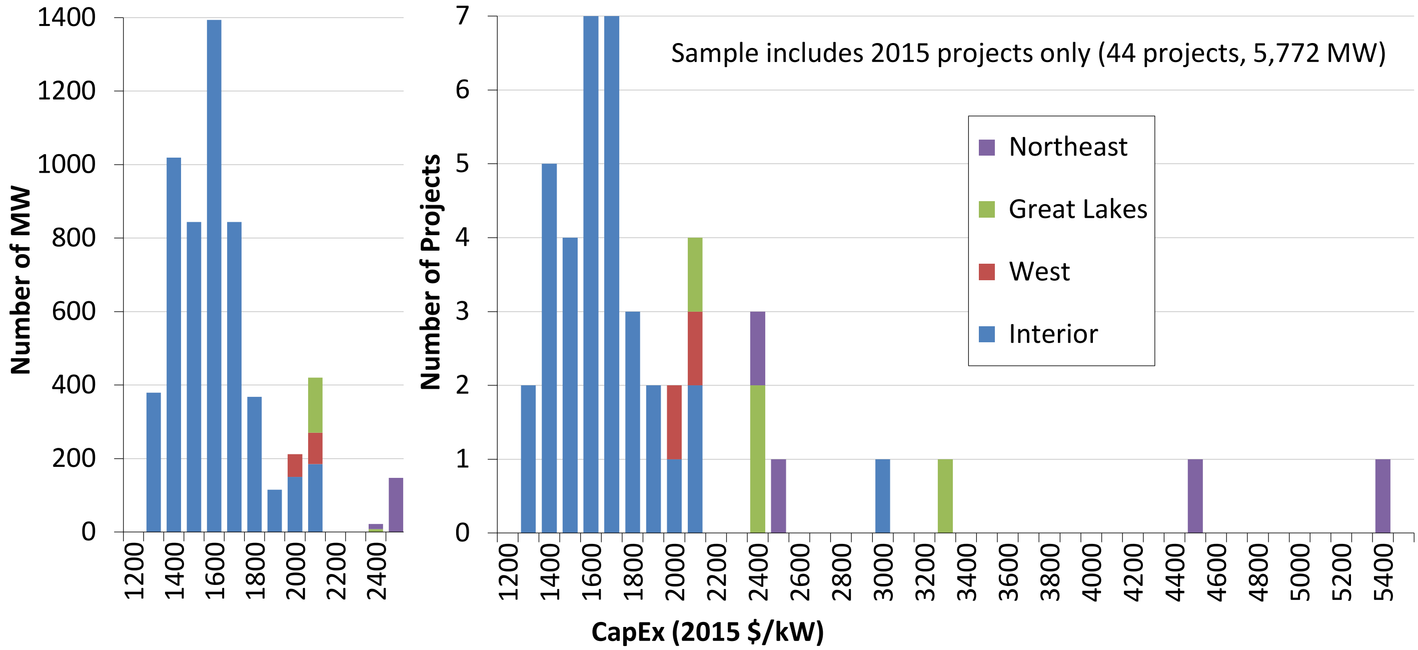


Source: Berkeley Lab

Figure 43. Installed wind power project costs by region: 2015 projects

Finally, Figure 44 shows two histograms that present the distribution of installed project costs among 2015-vintage projects, in terms of both capacity and number of projects. The four projects with costs above $3,000/kW are evident in the histogram of projects, but given their small size, they do not really show up in the capacity histogram; hence it is truncated at $2,500/kW. More generally, it is clear that most of the projects—and all of the low-cost projects—are located in the Interior region, where the distribution is centered on the $1,600-$1,700/kW bin. Projects in other regions have higher costs.

[52] Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 43.



Note: The capacity histogram is truncated at $2,500/kW as a space-saving measure, given that the four projects that have higher costs are all very small and hence imperceptible on the capacity histogram.

Source: Berkeley Lab

Figure 44. Histogram of installed costs by MW and projects: 2015 projects

Operations and maintenance costs varied by project age and commercial operations date

Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 154 installed wind power projects in the United States, totaling 12,080 MW with commercial operation dates of 1982 through 2014. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the facility, as well as rent.[53] Other ongoing expenses, including general and administrative expenses, taxes, property insurance,

[53] The vast majority of the recent data derive from FERC Form 1, which 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 not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under “electric plant” accounts rather than maintenance accounts.

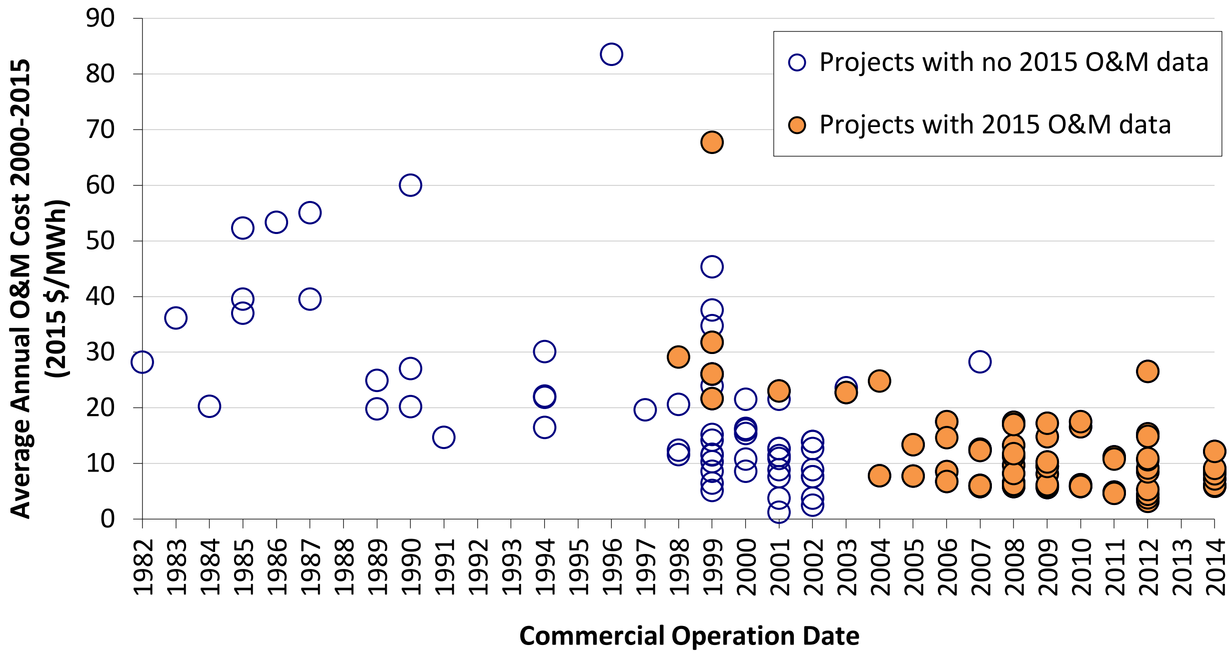
depreciation, and workers' compensation insurance, are generally not included. As such, the following figures are not representative of total operating expenses for wind power projects; the last paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow should be taken as indicative of potential overall trends. Note finally that the available data are presented in $/MWh terms, as if O&M represents a variable cost; in fact, O&M costs are in part variable and in part fixed. Although not presented here, expressing O&M costs in units of $/kW-year yields qualitatively similar results to those presented in this section.

Figure 45 shows project-level O&M costs by commercial operation date.[54] Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2015, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2014, only year 2015 data are available, and that is what is shown in the figure.[55] Many other projects only have data for a subset of years during the 2000–2015 timeframe, either because they were installed after 2000 or because a full time series is not available, so each data point in the chart may represent a different averaging period within the overall 2000–2015 timeframe. The chart highlights the 71 projects, totaling 8,465 MW, for which 2015 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 45 also suggests that projects installed within the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2015 O&M costs for the 24 projects in the sample constructed in the 1980s equal $35/MWh, dropping to $24/MWh for the 37 projects installed in the 1990s, to $10/MWh for the 65 projects installed in the 2000s, and to $9/MWh for the 28 projects installed since 2010.[56] This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and manufacturer warranties expire;[57]

[54] For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.
[55] Projects installed in 2015 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2015 would be year 2016.
[56] If expressed instead in terms of $/kW-year, capacity-weighted average 2000–2015 O&M costs were $68/kW-year for projects in the sample constructed in the 1980s, dropping to $57/kW-year for projects constructed in the 1990s, to $28/kW-year for projects constructed in the 2000s, and to $26/kW-year for projects constructed since 2010. Somewhat consistent with these observed O&M costs, Bloomberg NEF (2016c) shows a general reduction in the cost of a sample of initial full-service O&M contracts (pertaining to the first years of turbine life, and only about 4 GW of which are from North America) since 2008, reaching 21.6 Euro/kW-year in 2015 (~$24/kW-year). An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 5 GW of operating wind projects (with only about half that amount having been operable for longer than five years) also shows average levels of expenditure consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).
[57] Many of the projects installed more recently may still be within their turbine manufacturer warranty period, and/or may have capitalized O&M service contracts within their turbine supply agreement. Projects choosing the Section 1603 cash grant over the PTC may have had a particular incentive to capitalize service contracts (29 projects totaling 44% of the sample capacity installed since 2000 were installed from 2009-2012—i.e., within the period of eligibility for the Section 1603 grant—though only five of these 29 projects actually elected the grant over the PTC). In either case, reported O&M costs will be artificially low.

and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a per-MWh basis.

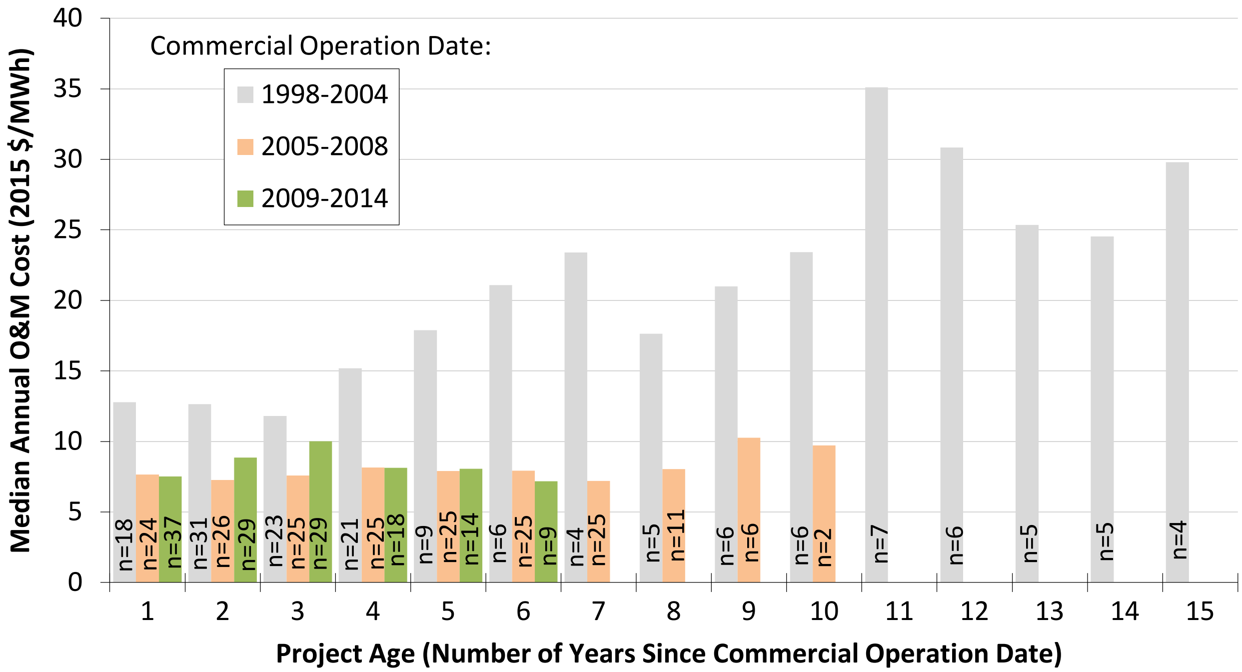


Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 45. Average O&M costs for available data years from 2000–2015, by commercial operation date

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 46 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale, which reportedly can be significant (Bloomberg NEF 2016c). Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially.

With these limitations in mind, Figure 46 shows an upward trend in project-level O&M costs as projects age, at least among the oldest projects in our sample – i.e., those built from 1998-2004 – although the sample size after year 4 is rather limited for these earliest projects. This upward trend is consistent with Bloomberg NEF (2016c) data showing that O&M contract renewals are more expensive than initial service agreements. In addition, the figure shows that projects installed more recently (from 2005–2008 and/or 2009-2014) have had, in general, lower O&M costs than those installed in earlier years (from 1998–2004), at least for the first 10 years of operation. Parsing the "recent project" cohort into two sub-periods, however, reveals that this trend towards lower costs has not necessarily continued with the most recent projects in the sample; cost differences between the 2005-2008 and 2009-2014 project samples are small, with no consistent trend as projects age.



Source: Berkeley Lab; medians shown only for groups of two or more projects, and only projects >5 MW are included

Figure 46. Median annual O&M costs by project age and commercial operation date

As indicated previously, the data presented in Figures 45 and 46 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a public company that owned more than 4 GW of U.S. wind project assets at the end of 2015 (all of which has been installed since 2000), indicate markedly higher total operating costs.[58] Specifically, EDPR (2016) reported total operating expenses of $25.5/MWh for its U.S. wind project portfolio in 2015[59] – i.e., more than twice the ~$10/MWh average O&M cost reported above for the 93 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between EDPR and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, EDPR breaks out its total U.S. operating costs in 2015 ($25.5/MWh) into three categories: supplies and services, which "includes O&M costs" ($13.5/MWh); personnel costs ($4.0/MWh); and other operating costs, which "mainly includes operating taxes, leases, and rents" ($7.9/MWh). Among these three categories, the $13.5/MWh for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings (i.e., that turbine and balance-of-plant O&M costs make up only about half of total operating costs), NREL analysis based on data from DNV KEMA on plants commissioned before 2009 shows total operating expenditures of $40–$60/kW-year depending on project age, with turbine and balance-of-plant O&M costs representing roughly half of those expenditures (Lantz 2013).

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[58] Past editions of this report also reported O&M costs for Infigen, but in October 2015 Infigen's U.S. wind assets were sold to a privately held company that does not file public financial statements.
[59] Though not entirely clear, EDPR's reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed.

7. Wind Power Price Trends

Earlier sections documented trends in capacity factors, wind turbine prices, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices presented in this chapter. In general, higher-cost and/or lower-capacity-factor projects will require higher PPA prices, while lower-cost and/or higher-capacity-factor projects can have lower PPA prices.

Berkeley Lab collects data on wind PPA prices from the sources listed in the Appendix, resulting in a dataset that currently consists of 387 PPAs totaling 34,558 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2016 or 2017. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs), and most of them have a utility as the counterparty.[60]

Except where noted, PPA prices are expressed throughout this chapter on a levelized basis over the full term of each contract, and are reported in real 2015 dollars.[61] Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.[62] Whenever they are broken out by time, the date on (or year in) which the PPA was signed or executed is used, as that date provides the best indication (i.e., better than commercial operation date) of market conditions at the time. Finally, because the PPA prices in the Berkeley Lab sample are reduced by the receipt of state and federal incentives (e.g., the levelized PPA prices reported here would be at least $15/MWh higher without the PTC, ITC, or Treasury Grant[63]) and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs.

[60] Though we do have pricing details for some PPAs with corporate off-takers, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a "contract for differences" with the corporate off-taker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through our traditional sources, like regulatory filings). Though only a minor omission at present, this distinction could limit our sample more severely in the future if the popularity of corporate offtake agreement continues to grow at its current pace.

[61] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 34 years, with 20 years being by far the most common (at 58% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.

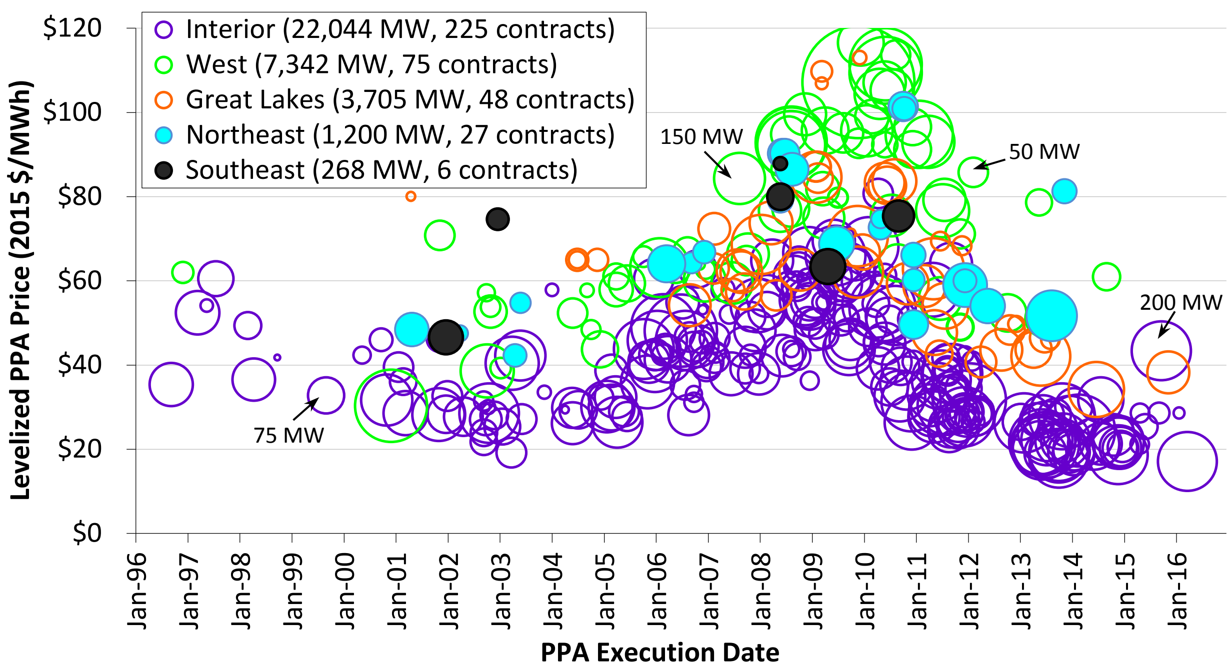
[62] Generation weighting is based on the empirical project-level performance data analyzed earlier in this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. In cases where there is not enough operational history to establish a "steady-state" pattern of performance, we used discretion in estimating appropriate weights (to be updated in the future as additional empirical data become available).

[63] The estimated levelized PPA price impact of ~$15/MWh is less than the PTC's 2015 face value of $23/MWh for several reasons. First, the PTC is a 10-year credit, whereas most PPAs are for longer terms (e.g., 20 years). Second, the PTC is a tax credit, and must be converted to pre-tax equivalent terms before being compared to PPA prices. Finally, the presence of the PTC constrains financing choices for many wind project owners and drives up the project's weighted average cost of capital. In other words, if not for the PTC, projects could be financed more cheaply; this difference in the weighted average cost of capital with and without the PTC erodes some of the PTC's value (for more information, see Bolinger (2014)).

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to wholesale power prices, and compared to future natural gas prices. In addition, REC prices are presented in a text box on page 67.

Wind PPA prices remain very low

Figure 47 plots contract-level levelized wind PPA prices by contract execution date, showing a clear downward trend in PPA prices since 2009 and 2010—both overall and by region (see Figure 29 for regional definitions).[64] This trend is particularly evident within the Interior region, which—as a result of its low average project costs and high average capacity factors shown earlier in this report—also tends to be the lowest-priced region over time. Prices generally have been higher in the rest of the United States.[65]



Note: Area of "bubble" is proportional to contract nameplate capacity

Source: Berkeley Lab

Figure 47. Levelized wind PPA prices by PPA execution date and region

Figure 48 provides a smoother look at the time trend nationwide (the blue columns) by averaging the individual levelized PPA prices shown in Figure 47 by year. After topping out at nearly $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around the $20/MWh level—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced

[64] Roughly 99% of the contracts that are depicted in Figure 47 are from projects that are already online. For the most part, only the most recent contracts in the sample are from projects that are not yet online.

[65] Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region's physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market influences.

Interior region of the country where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~$55/MWh among contracts executed in 2009 to ~$20/MWh today. The temporary price spike among PPAs signed in 2015 is attributable to a small sample (just six projects totaling 401 MW) that is dominated by two higher-priced contracts totaling 300 MW, one of which is located in the Interior region but is selling into California (which perhaps explains the higher price).

The trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent project vintages, as documented in Chapter 5. This combination of declining costs and improved performance (along with historically low interest rates, as shown earlier in Figure 17) has enabled wind PPA prices to fall to today's record-low levels.

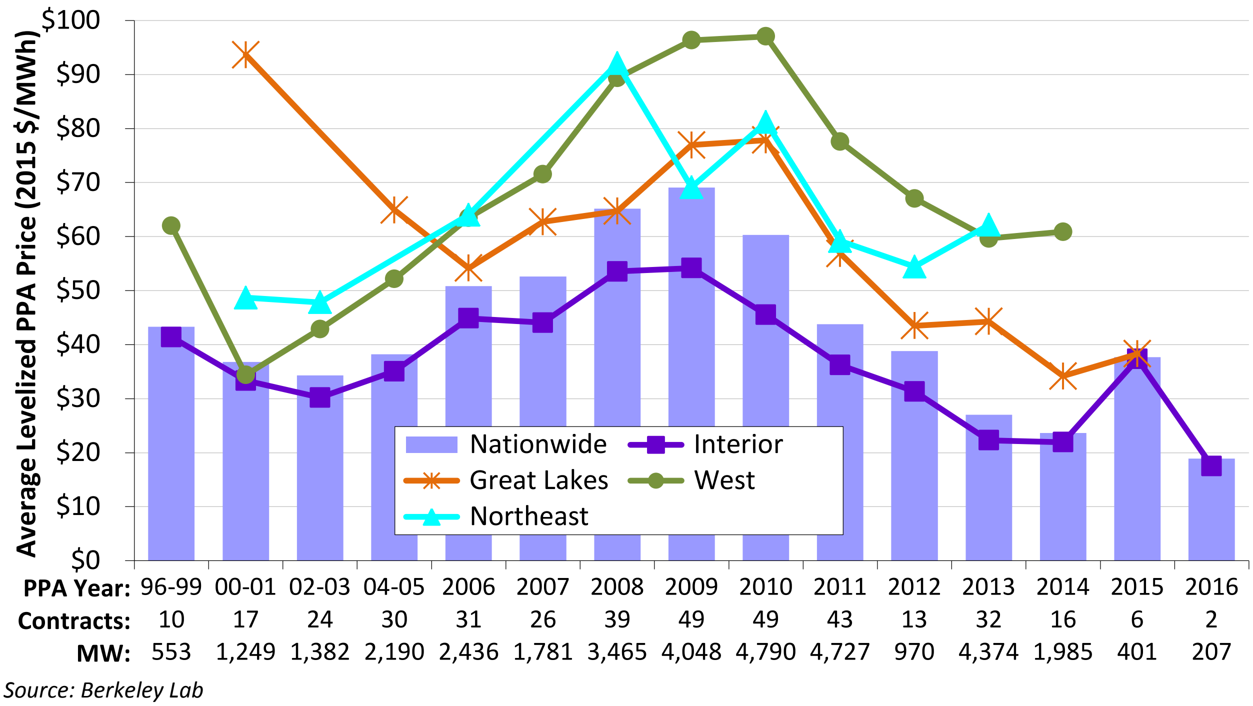
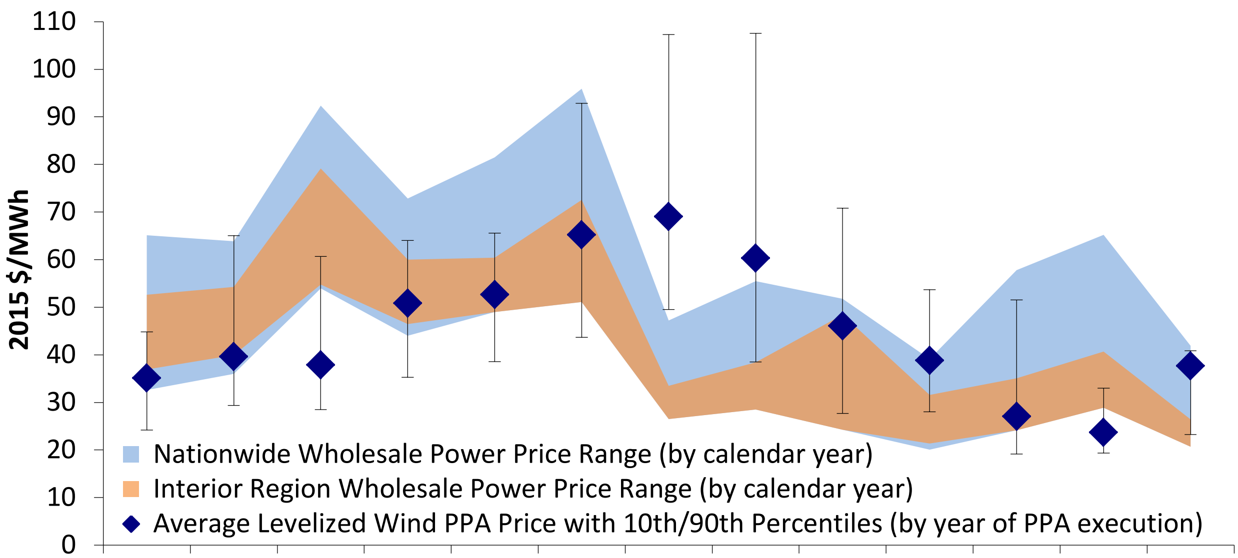


Figure 48. Generation-weighted average levelized wind PPA prices by PPA execution date and region

Figure 48 also shows trends in the generation-weighted average levelized PPA price over time among four of the five regions broken out in Figure 29 (the Southeast region is omitted from Figure 48 owing to its small sample size). Figures 47 and 48 both demonstrate that, based on our contract sample, PPA prices are generally low in the U.S. Interior, high in the West, and moderate in the Great Lakes and Northeast regions. As shown by the close agreement between the two, the large Interior region—where much of U.S. wind project development occurs—dominates the nationwide sample, particularly in recent years.

The relative economic competitiveness of wind power declined in 2015 with the drop in wholesale power prices

The blue-shaded area of Figure 49 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[66] going back to 2003 at 23 different pricing nodes located throughout the country (refer to the Appendix for the names and approximate locations of the 23 pricing nodes represented by the blue-shaded area). Similarly, the orange-shaded area shows the range of wholesale prices among only those nodes that are located within the Interior region. Our PPA price sample is increasingly dominated by projects in this region. Finally, the dark diamonds represent the generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 48).



Year:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Contracts:	9	13	17	31	26	39	49	49	43	13	32	16	6
MW:	570	547	1,643	2,436	1,781	3,465	4,048	4,790	4,727	970	4,374	1,985	401

Source: Berkeley Lab, FERC, ABB, IntercontinentalExchange

Figure 49. Average levelized long-term wind PPA prices and yearly wholesale electricity prices over time

At least within the sample of projects reported here, average long-term wind PPA prices compared favorably to yearly wholesale electricity prices from 2003 through 2008. Starting in 2009, however, the sharp drop in wholesale electricity prices (driven primarily by lower natural gas prices) squeezed average wind PPA prices out of the wholesale power price range on a

[66] A flat block of power is defined as a constant amount of electricity generated and sold over a specified period. Although wind power projects do not provide a flat block of power, as a common point of comparison a flat block is not an unreasonable starting point. In other words, the time variability of wind energy is often such that its wholesale market value is somewhat lower than, but not too dissimilar from, that of a flat block of (non-firm) power, at least at lower levels of wind penetration (Fripp and Wiser 2006). At higher levels of wind penetration, wind power can suppress local wholesale power prices during times of peak output and/or low demand, thereby eroding its value in the wholesale market relative to a flat block of power.

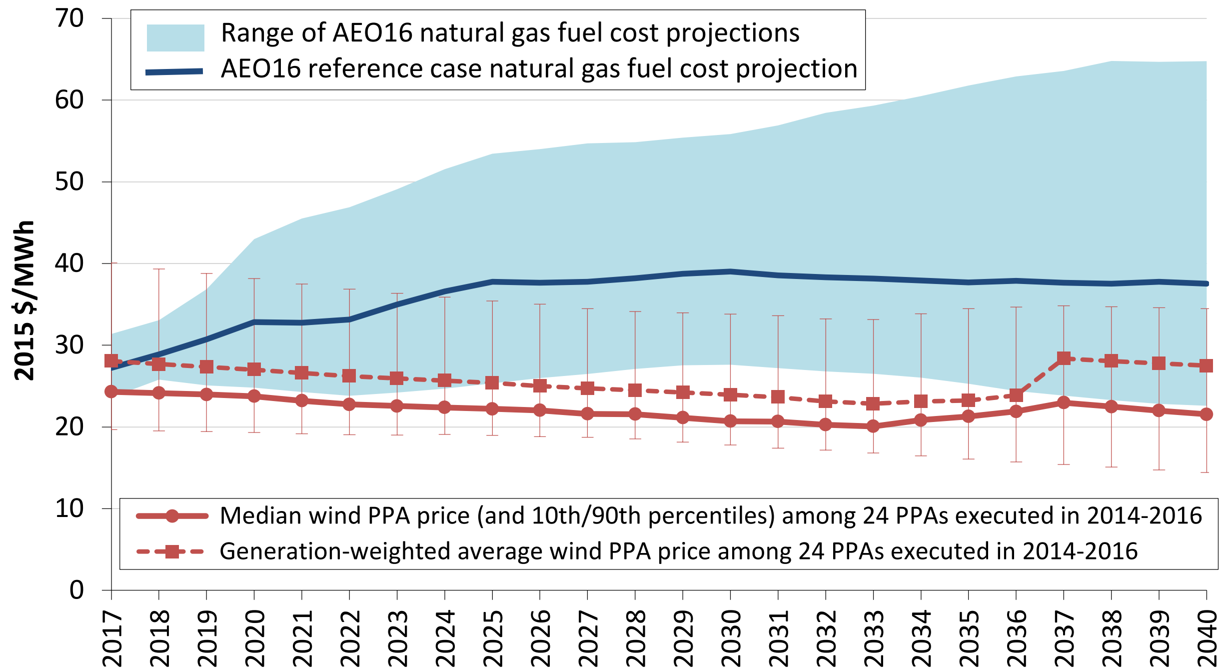
nationwide basis. Wind PPA prices have since fallen, however, and in 2011 and 2012 reconnected with the upper end of the wholesale power price range. In 2013 and 2014, further PPA price declines, along with a bit of a rebound in wholesale prices, put wind back at the bottom of the range once again. Subsequently, the sharp drop in average wholesale electricity prices in 2015 has made it somewhat harder for wind to compete in the market. The spike in PPA prices among the small sample of 2015 projects mentioned above did not help, though focusing on the 10th to 90th percentile range rather than the weighted-average PPA price perhaps provides a more representative comparison in that year. Even so, the much narrower and lower range of wholesale power prices in the Interior region is arguably the more relevant comparison in recent years, as project development has been largely concentrated within that region.

The comparison between levelized wind PPA and wholesale power prices in Figures 49 is imperfect, in part because the levelized wind PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale power prices are pertinent to just the single year in question. Figure 50 attempts to remedy this temporal mismatch by presenting an alternative (yet still imperfect) way of looking at how wind stacks up relative to its competition.

Rather than levelizing the wind PPA prices, Figure 50 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) from PPAs executed in 2014, 2015, or 2016 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[67] As shown, the median and generation-weighted average wind PPA prices from contracts executed in the past three years are consistently at or below the low end of the projected natural gas fuel cost range over the entire period, while the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall below the reference case projection and into the lower portion of the fuel cost range from 2024-2040.

Figure 50 also hints at the long-term value that wind power can provide as a "hedge" against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could ultimately be lower or much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

[67] The fuel cost projections come from the EIA's *Annual Energy Outlook 2016* publication, and increase from around \$3.89/MMBtu in 2017 to \$5.36/MMBtu (both in 2015 dollars) in 2040 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from \$/MMBtu into \$/MWh using a flat heat rate of 7 MMBtu/MWh, which is aggressive compared to the heat rates implied by the reference case modeling output (which start at roughly 7.9 MMBtu/MWh in 2017 and gradually decline to just above 7 MMBtu/MWh by 2040).



Source: Berkeley Lab, EIA

Figure 50. Wind PPA prices and a natural gas fuel cost projections by calendar year over time

Important Note: Notwithstanding the comparisons made in this section, neither the wind nor wholesale electricity prices (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind PPA and wholesale power prices in this manner are the following:

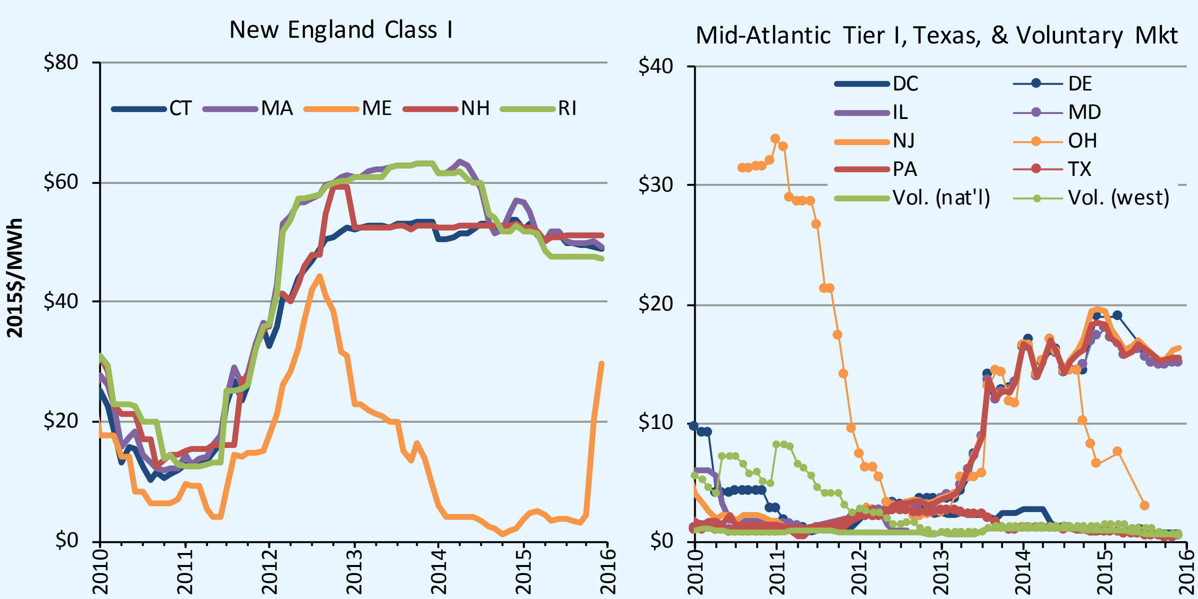
- Wind PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by virtue of any financial incentives provided to fossil-fueled generation and its fuel production, as well as by not fully accounting for the environmental and social costs of fossil generation.
- Wind PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs, and may not fully reflect capital and fixed (or variable) operating costs.
- Wind PPA prices—once established—are fixed and known, whereas wholesale electricity prices are short-term and therefore subject to change. As shown in Figure 50, EIA projects natural gas prices to rise from current levels, resulting in an increase in wholesale electricity prices.
- The location of the sampled wholesale electricity nodes and the assumption of a flat block of power are not perfectly consistent with the location and output profile of the sample of wind power projects. Especially at higher penetrations and in locations where wind generation profiles are poorly correlated with local load profiles, excessive wind generation during times of peak output and/or low load can push the wholesale market value of wind power well below that of a flat block of power.

In short, comparing levelized long-term wind PPA prices with either yearly wholesale electricity prices or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to its competition. Nonetheless, these comparisons still provide some sense for the short-term competitive environment facing wind energy, and convey how that environment has shifted over time.

REC Prices Remained Near "Alternative Compliance Payment" Levels in the Northeast, While Falling Modestly among Mid-Atlantic States

The wind power sales prices presented in this report reflect only the bundled sale of both electricity and RECs; excluded are projects that sell RECs separately from electricity, thereby generating two sources of revenue. REC markets are somewhat fragmented in the United States but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis.

The figures below present indicative data of spot-market REC prices in both compliance and voluntary markets. Data for compliance markets focus on "Class I" or "Tier I" RPS requirements, as these are the RPS compliance markets in which wind energy would typically participate. Clearly, spot REC prices have varied substantially, both across states and over time within individual states, though prices within regional power markets (New England and the Mid-Atlantic) are linked to varying degrees. In New England compliance markets (other than Maine), REC prices in 2015 remained relatively high; prices hovered around the $55/MWh alternative compliance payment (ACP) rate in Connecticut and Rhode Island, reflecting an expectation of continued under-supply in the region. Among Mid-Atlantic states, REC pricing generally ranged from $15-20/MWh, falling modestly over the course of the year. Prices for RECs offered in the national and western voluntary markets and for RPS compliance in Texas remained at roughly $1/MWh throughout the year, reflecting sustained over-supply.



Notes: Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded.

Source: Marex Spectron.

8. Policy and Market Drivers

A long-term extension and phase down of federal incentives for wind projects is leading to a resurgent domestic market

Various policy drivers at both the federal and state levels, as well as federal investments in wind energy research and development (R&D), have been important to the expansion of the wind power market in the United States. At the federal level, the most important policy incentives in recent years have been the PTC (or, if elected, the ITC) and accelerated tax depreciation.

Initially established in 1994, the PTC provides a 10-year, inflation-adjusted credit that stood at $23/MWh in 2015 (Table 5). The historical importance of the PTC to the U.S. wind industry is illustrated by the pronounced lulls in wind additions in the 4 years (2000, 2002, 2004, 2013) during which the PTC lapsed as well as the increased development activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 1).

In December 2015, Congress passed a long term, 5-year extension of the PTC (or, if elected, the ITC). To qualify, projects must begin construction before January 1, 2020. Moreover, in May 2016, the IRS issued favorable guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. This new guidance lengthened the “safe harbor” completion period from the previous term of two years.

In extending the PTC, Congress also put the wind industry on a glide path to a lower PTC, with a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in 20%-per-year increments for projects starting construction in 2017 (80% PTC value), 2018 (60%), and 2019 (40%).

In addition to the PTC, a second form of federal tax support for wind is accelerated tax depreciation, which historically has enabled wind project owners to depreciate the vast majority of their investments over a 5- to 6-year period for tax purposes. Even more attractive “bonus depreciation” schedules have been periodically available, since 2008.

The near-term availability of the PTC is leading a resurgence of the U.S. wind power market, with solid continued growth in capacity additions expected over the next five years. The PTC phase down, on the other hand, imposes longer-term risks. Potentially helping to partially fill that void are the prospective impacts of more-stringent EPA environmental regulations on fossil plant retirement, energy costs, and demand for clean energy—which may create new opportunities for wind in the longer term. Of note are the actions to address carbon emissions that have been initiated at the EPA through the Clean Power Plan, though those regulations remain in limbo as legal challenges are resolved. Finally, R&D investments by the DOE continue, and could further reduce the cost of wind energy.

Table 5. History of the Production Tax Credit Extensions

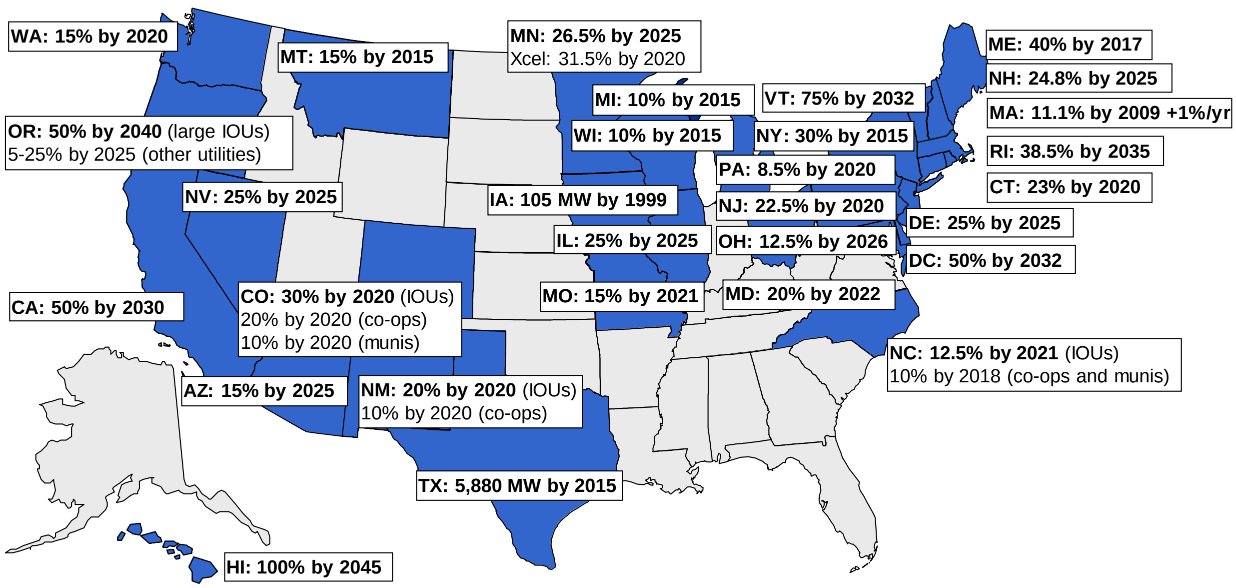
Legislation	Date Enacted	Start of PTC Window	End of PTC Window	Effective PTC Planning Window (considering lapses and early extensions)
Energy Policy Act of 1992	10/24/1992	1/1/1994	6/30/1999	80 months
Ticket to Work and Work Incentives Improvement Act of 1999	12/19/1999 *(lapsed for >5 months)*	7/1/1999	12/31/2001	24 months
Job Creation and Worker Assistance Act	3/9/2002 *(lapsed for >2 months)*	1/1/2002	12/31/2003	22 months
The Working Families Tax Relief Act	10/4/2004 *(lapsed for >9 months)*	1/1/2004	12/31/2005	15 months
Energy Policy Act of 2005	8/8/2005	1/1/2006	12/31/2007	29 months
Tax Relief and Healthcare Act of 2006	12/20/2006	1/1/2008	12/31/2008	24 months
Emergency Economic Stabilization Act of 2008	10/3/2008	1/1/2009	12/31/2009	15 months
The American Recovery and Reinvestment Act of 2009	2/17/2009	1/1/2010	12/31/2012	46 months
American Taxpayer Relief Act of 2012	1/2/2013 *(lapsed for 1-2 days)*	1/1/2013	Start construction by 12/31/2013	12 months (in which to start construction)
Tax Increase Prevention Act of 2014	12/19/2014 *(lapsed for >11 months)*	1/1/2014	Start construction by 12/31/2014	2 weeks (in which to start construction)
Consolidated Appropriations Act of 2016	12/18/2015 *(lapsed for >11 months)*	1/1/2015	Start construction by 12/31/2016	12 months to start construction and receive 100% PTC value
			Start construction by 12/31/2017	24 months to start construction and receive 80% PTC value
			Start construction by 12/31/2018	36 months to start construction and receive 60% PTC value
			Start construction by 12/31/2019	48 months to start construction and receive 40% PTC value

Notes: Although the table pertains only to PTC eligibility, the *American Recovery and Reinvestment Act of 2009* enabled wind projects to elect a 30% investment tax credit (ITC) in lieu of the PTC starting in 2009; though it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase down schedule as the PTC, as noted in the table: from 30% to 24% to 18% to 12%). Section 1603 of the same law enabled wind projects to elect a 30% cash grant in lieu of either the 30% ITC or the PTC; this option was only available to wind projects that were placed in service from 2009-2012 (and that had started construction prior to the end of 2011), and was widely used during that period. Finally, beginning with the *American Taxpayer Relief Act of 2012*, which extended the PTC window through 2013, the traditional "placed in service" deadline was changed to a more-lenient "construction start" deadline, which has persisted in the two subsequent extensions. Related, the IRS initially issued safe harbor guidelines providing projects that meet the applicable construction start deadline up to two full years to be placed in service (without having to prove continuous effort) in order to qualify for the PTC. In May 2016, the IRS lengthened this safe harbor window to four full years.

Source: Berkeley Lab

State policies help direct the location and amount of wind power development, but current policies cannot support continued growth at recent levels

As of July 2016, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 51).[68] Attempts to weaken RPS policies have been initiated in a number of states, and in limited cases—thus far only Ohio in 2014 and Kansas in 2015—have led to a freeze or repeal of RPS requirements. In contrast, other states—including, most recently, California, Hawaii, Oregon, Rhode Island, and Washington, DC—have increased and extended their RPS targets. Vermont has created a new RPS.



Notes: The figure does not include mandatory RPS policies established in U.S. territories or non-binding renewable energy goals adopted in U.S. states and territories. Note also that many states have multiple "tiers" within their RPS policies, though those details are not summarized in the figure.

Source: Berkeley Lab

Figure 51. State RPS policies as of July 2016

Of all wind power capacity built in the United States from 2000 through 2015, roughly 51% is delivered to load serving entities (LSEs) with RPS obligations. In recent years, however, the role of state RPS programs in driving incremental wind power growth has diminished, at least on a national basis; just 24% of U.S. wind capacity additions in 2015 serve RPS requirements. Outside of the wind-rich Interior region, however, 88% of wind capacity additions in 2015 are serving RPS demand, and RPS requirements continue to serve as a strong driver for wind power growth.

In aggregate, existing state RPS policies will require 420 terawatt-hours of RPS-eligible forms of renewable electricity by 2030, at which point most state RPS requirements will have reached their maximum percentage targets. Based on the mix and capacity factors of resources currently used or contracted for RPS compliance, this equates to a total of roughly 130 GW of RPS-

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[68] Although not shown in Figure 51, mandatory RPS policies also exist in a number of U.S. territories, and non-binding renewable energy goals exist in a number of U.S. states and territories.

eligible renewable generation capacity needed to meet RPS demand in 2030.[69] Given current renewable energy supplies available for RPS compliance, Berkeley Lab estimates that existing state RPS programs will require roughly 55 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2015.[70] This equates to an average annual build-rate of roughly 3.7 GW per year, not all of which will be wind. This is below the average of 6.6 GW of wind power capacity added in each year over the past decade, and even further below the average 9.5 GW per year of total renewable generation capacity added during that time frame.

In addition to state RPS policies, utility resource planning requirements, principally in Western and Midwestern states, have spurred wind power additions in recent years. So has voluntary customer demand for "green" power (see box below for a discussion of burgeoning commercial interest in wind energy). State renewable energy funds provide support (both financial and technical) for wind power projects in some jurisdictions, as do a variety of state tax incentives. Finally, concerns about the possible impacts of global climate change continue to fuel interest in implementing and enforcing carbon reduction policies in some states and regions. The Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy, for example, has been operational for a number of years, and California's greenhouse gas cap-and-trade program commenced operation in 2012, although carbon pricing seen to date has been too low to drive significant wind energy growth. How these dynamics will evolve as the EPA steps in to regulate power sector carbon emissions through the Clean Power Plan, and the role that RPS programs will play in achieving carbon emissions targets, both remain unclear.

[69] Berkeley Lab's projections of new renewable capacity required to meet each state's RPS requirements assume different combinations of renewable resource types for each RPS state. Those assumptions are based, in large part, on the actual mix of resources currently used or under contract for RPS compliance in each state or region. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis, or are met with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.

[70] This estimate of required renewable electricity capacity additions is derived by comparing, on a region-by-region basis, the total amount of renewable capacity required for RPS demand in 2030 to the current installed base of renewable capacity deemed "available" for RPS compliance. Individual renewable generation facilities are deemed available for RPS compliance if they are currently under contract to LSEs with RPS obligations or if the energy is sold on a merchant basis into regional power markets with active RPS obligations. This analysis ignores several complexities that could result in either higher or lower incremental capacity needs, including: retirements of existing renewable capacity, constraints on intra-regional trade of renewable energy and RECs, and the possibility that resources currently serving renewable energy demand outside of RPS requirements (e.g., voluntary corporate procurement) might become available for RPS demand in the future.

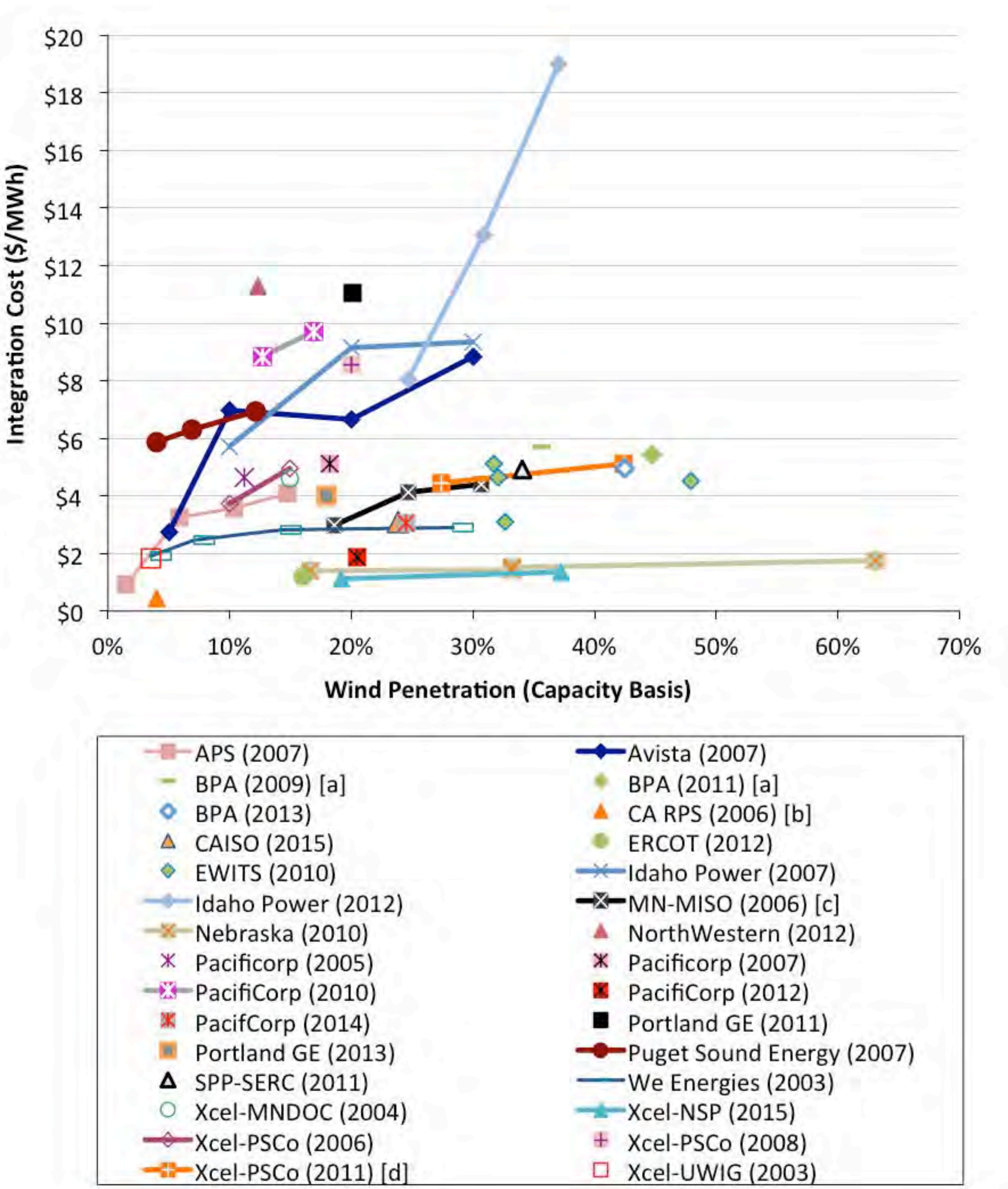
System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain

Wind energy output is variable and often the areas with the best wind speeds are distant from load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues have affected, and continue to impact, the pace of wind power deployment in the United States. Experience in operating power systems with wind energy is also increasing worldwide, leading to an emerging set of recently published best practices (e.g., Jones 2014, Milligan et al. 2015).

Figure 52 provides a selective listing of estimated wind integration costs at various levels of wind power capacity penetration from studies completed from 2003 through 2015. With one exception, costs estimated by the studies reviewed are below \$12/MWh—and often below \$5/MWh—for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the power is delivered. Variations in estimated costs across studies are due, in part, to differences in methodologies, definitions of integration costs, power system and market characteristics, wind energy penetration levels, fuel price assumptions, wind output forecasting details, and the degree to which thermal power plant cycling costs are included.[71]

Two new integration cost studies were completed in 2015: one for Northern States Power (NSP) in Minnesota as part of the Xcel-Minnesota integrated resource plan (NSP 2015), and one for the California IOUs as part of the Long Term Procurement Planning process (SCE 2015). The NSP integration costs of \$1.1–1.34/MWh in the most recent study are lower than the costs in previous studies in Minnesota due to the more-sophisticated operating practices currently employed by MISO than assumed in previous studies. The costs are primarily due to cycling coal and managing day-ahead forecast errors. The \$3.10/MWh integration cost for wind in California is an estimate of the marginal integration cost to accommodate more wind than already planned to meet the 33% RPS. Subsequent analysis by the authors, however, found that the estimates were unreliable largely due to methodological challenges in estimating integration costs (SCE 2016).

[71] Caveats on the interpretation and comparability of these costs discussed in previous versions of this report still apply here.



Notes: [a] Costs in $/MWh assume 31% capacity factor; [b] Costs represent 3-year average; [c] Highest over 3-year evaluation period; [d] Cost includes the coal cycling costs found in Xcel Energy (2011). Listed below the figure are the organizations for which each study was conducted, and the year in which the analysis was conducted or published.

Figure 52. Integration costs at various levels of wind power capacity penetration

In addition to studying wind integration costs, system operators and planners continue to make progress integrating wind into the power system. Strategies for reducing the challenges with wind integration include improved integration of wind into markets and improved coordination between balancing authorities:

- A recent wind integration study by the Southwest Power Pool (SPP 2016a) examined a scenario with enough wind to a have 60% instantaneous wind penetration. Even with additional transmission investments, significant wind curtailment was required to re-dispatch generation around contingency constraints. The study found that curtailment of wind could be substantially reduced if a greater share of wind participated in the market as a dispatchable variable energy resource, and recommended acceleration of certain transmission upgrades.
- ISO-NE is implementing a program to provide dispatch signals to wind generators through a "Do Not Exceed" dispatch program. The signal represents the maximum generation that can be accepted by each wind plant without affecting reliability. Similar to SPP findings, using this signal to control wind will lower overall wind curtailments and increase utilization of the transmission system.
- MISO incorporated a ramp product into its market operations to better manage uncertainty and variability—from wind, in some cases—and to provide a clear price signal for the value of flexible generation.
- In part due to growing shares of wind energy, ERCOT has proposed revisions to its ancillary service markets to unbundle different products and fine-tune requirements to match system conditions and resource capabilities. An economic analysis indicates that the improvements in market design could create benefits on the order of $200 million over the next ten years (Newell et al. 2015).
- In June 2015, SPP began providing balancing services to the Western Area Power Administration's Upper Great Plains Region (WAPA-UGP), Basin Electric Power Cooperative and Heartland Consumers Power District. In October, the three utilities transferred control of their transmission system to SPP. WAPA-UGP is the first federal power marketing administration to become a full member of a regional transmission organization (RTO).
- The western Energy Imbalance Market (EIM) now includes the CAISO, PacifiCorp, and NV Energy. The EIM allows for increased transfers between the participating balancing authorities and it increases diversity of resources. As of the first quarter of 2016, the EIM was averaging $6.3 million per month in consumer benefits and was reducing renewables curtailment by an average of 38 GWh/month (CAISO 2016). Work is underway to integrate Puget Sound Energy, Arizona Public Service, Portland General Electric, and Idaho Power into the EIM. In addition, PacifiCorp is exploring the prospect of becoming a full participating transmission owner within the CAISO, though the governance structure for a multi-state ISO is likely to be the key issue.
- A flexibility assessment of the Western Interconnection found that it is technically feasible to obtain 40% of energy from renewables, though with increasing curtailment. Increased regional coordination of balancing areas and measures that increase load during times when curtailment would occur, such as charging energy storage, can lower the amount of curtailment (E3 2015).

Recent studies of wind integration have sometimes focused on conditions that are likely to be the most challenging. For example, a recent GE transient stability[72] study focused on spring light load, high wind periods in Wyoming when most of the region’s synchronous generators will be

[72] Transient stability is the ability of a synchronous power system to return to a stable condition following a relatively large disturbance.

offline (Miller et al. 2015). Maintaining stability after a major disturbance, like the loss of a large transmission line, will be challenging in some extreme hours under weak system conditions. Achieving acceptable performance is found to require combinations of traditional mitigation strategies, including the potential need for transmission system improvements, and non-traditional wind power plant controls. The changes to wind plant controls would alter the low voltage power logic in a wind plant to suppress active current during severe faults.

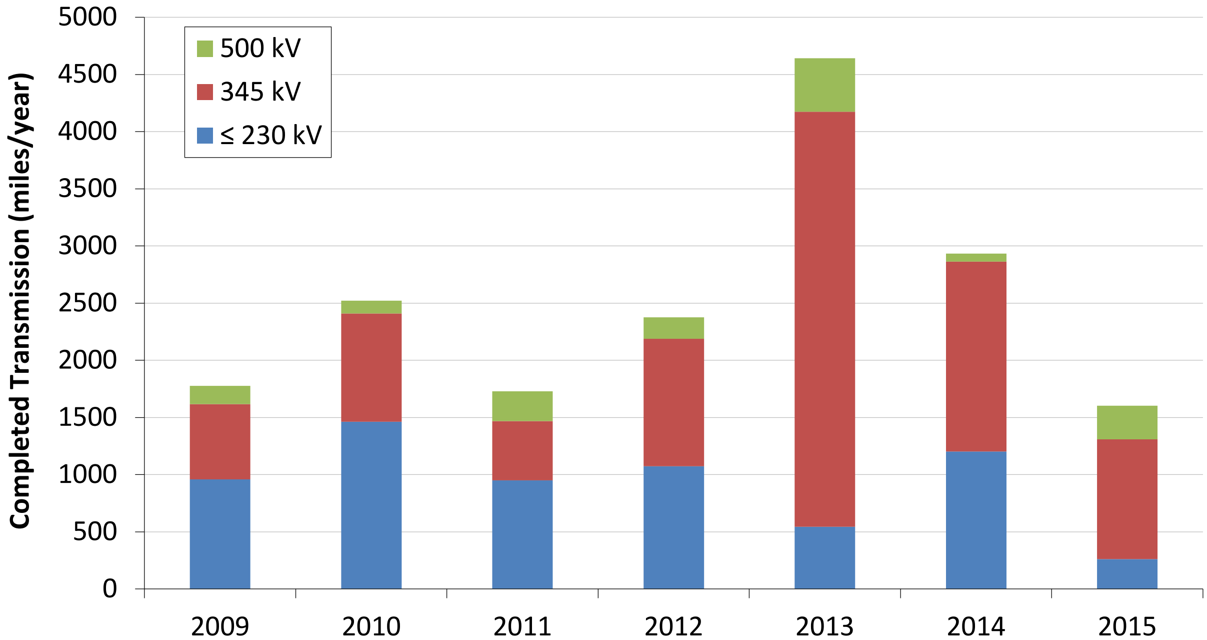
With growing shares of renewables and improvements to technology, wind is increasingly being asked to have the capability to supply grid services:

- FERC eliminated the exemption for asynchronous generators to provide reactive power for new interconnection requests in the pro forma Large Generator Interconnection Agreement (LGIA) and the Small Generator Interconnection Agreement (SGIA) (FERC 2016a). FERC cites the technological advances in inverters that make it inexpensive for new wind projects to be able to provide this function. FERC held a technical conference on compensation for reactive power supply in ISO markets in June 2016.
- FERC also released a Notice of Inquiry soliciting comments on whether the LGIA and SGIA should be revised to require all new generation resources to have frequency response capabilities as a precondition of interconnection (FERC 2016b). In addition, they asked whether existing resources should be required to have primary frequency response capabilities and arrangements for the provision and compensation of primary frequency response. FERC noted that ERCOT, ISO-NE, and PJM already require new generators, including wind in some cases, to have primary frequency response capabilities.
- NERC's Essential Reliability Services Task Force, noting a changing generation resource mix that includes more non-synchronous generation, recommends that all new resources have the capability to support voltage and frequency (NERC 2015).

It is also clear that transmission expansion helps to manage increasing wind energy:

- The recent wind integration study by SPP (SPP 2016a) confirmed the need for transmission projects already identified in the integrated transmission planning process and discovered additional transmission needs beyond the approved projects. Further, some of the approved transmission projects should be expedited so that the projects can be placed in-service sooner than originally scheduled. A separate study by SPP found that 348 transmission upgrades constructed between 2012 and 2014 will provide more than $16 billion in benefits over a 40-year period (SPP 2016b).
- The NSP wind integration study (EnerNex 2014) found that existing wind curtailment in the region is almost all due to transmission congestion. Wind curtailment is expected to be considerably lower after planned regional transmission solutions—identified through the Multi-Value Project Portfolio Analysis—are put in place. Separately, MISO found that its Multi-Value Project, a series of transmission projects encompassing eight states, will have a benefit-to-cost ratio varying from 2.6 to 3.9 and create net benefits of $13.1 to $49.6 billion.

Transmission additions, however, slowed in 2015 compared to previous years. About 1,500 miles of transmission lines came online in 2015, the lowest amount since FERC began publishing this data in 2009 (see Figure 53). As of March 2016, FERC (2016c) estimates that another 14,000 miles of new transmission lines (or line upgrades) are proposed to come online by March 2018, with about 5,500 miles of those having a high probability of completion. The Edison Electric Institute (EEI), meanwhile, projects that transmission investment will amount to $22 billion in both 2016 and 2017 before falling to $20 billion in 2018 (EEI 2015a). EEI states that 46 percent of the transmission projects it is tracking will, at least in part, support the integration of renewable energy (EEI 2015b).



Source: FERC monthly infrastructure reports

Figure 53. Miles of transmission projects completed, by year and voltage

Three major transmission projects that will transport wind energy were completed in 2015, summarized in Table 6. Moreover, AWEA (2016a) has identified 15 additional near-term transmission projects that, if all were completed, could transmit 52.4 GW of additional wind capacity, as depicted in Table 7.

Table 6. Transmission Projects Completed in 2015

Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
Big Eddy – Knight and Central Ferry – Lower Monumental (OR, WA)	500	2015	4,200
Maine Power Reliability Program	345, 115	2015	n/a
Most CapX Segments (MN, ND, SD, WI)	Mostly 345, some 230 and 165 lines	2014-16	2,000
Total Potential Wind Capacity			**6,200**

Source: AWEA (2016a)

Table 7. Planned Near-Term Transmission Projects and Potential Wind Capacity

Transmission Project Name (State)	Voltage (kilovolts)	Estimated In-service Date	Estimated Potential Wind Capacity, MW
Tehachapi Phases 2-3 (CA)	500	2016	3,800
MISO Multi-Value Projects (IA, IL, MI, MN, MO, ND, SD, WI)	345, one 765 line	2015-2020	14,000
Grand Prairie Gateway (IL)	345	2017	1,000
Nebraska City – Mullin Creek – Sibley (NE-MO; SPP Priority Project)	345	2017	(SPP Priority Project Component)
Southline Transmission Project (AZ, NM)	345, 230	2018	1,000
TransWest Express (WY)	600 DC	2018	3,000
Power for the Plains (NM, OK, TX)	115, 230, 345	2016-2020	n/a
Clean Line Projects (AZ, IA, KS, NM, OK)	600 DC	2018-2020	16,000
Pawnee – Daniels Park (CO)	345	2019-2020	500
Gateway West (ID, WY)	500	2019-2021	3,000
Sunzia (AZ, NM)	500	2020	3,000
Boardman-Hemingway (ID, OR)	500	2020	1,000
Gateway South (WY, UT)	500	2020-2022	1,500
SPP 2012 ITP10 Projects (KS, MO, OK, TX)	345	2018-2022	3,500
Total Potential Wind Capacity			**52,400**

Source: AWEA (2016a)

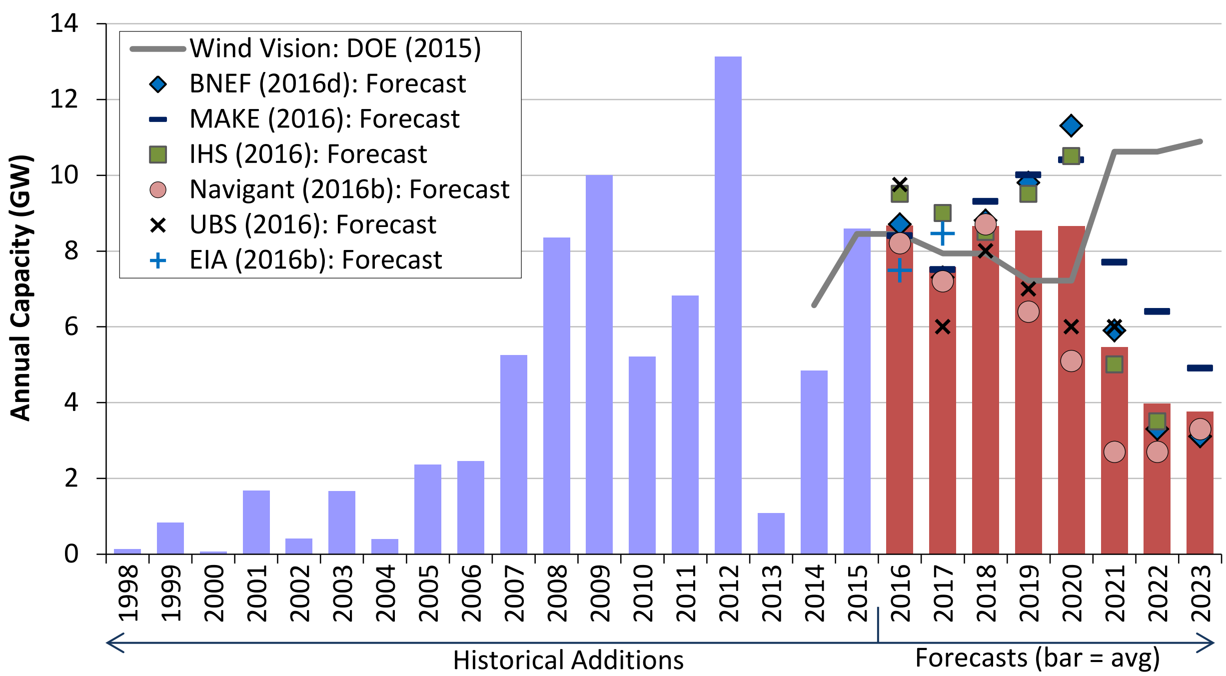
FERC held a technical conference in June 2016 to review the implementation of Order 1000, which was intended to improve intra- and inter-regional transmission planning and cost allocation. Order 1000 requires public utility transmission providers to: participate in a regional transmission planning process; establish procedures to identify transmission needs driven by public policy requirements; and coordinate with neighboring planning regions to solve mutual transmission needs (FERC 2011). Recent literature has suggested that Order 1000 needs to be re-examined. A 2015 report found that most transmission investments are based on meeting reliability needs, and that the increased market efficiency and economic benefits of transmission are not evaluated comprehensively in transmission plans. That same study found that inter-regional transmission planning is still very much in its infancy and has not resulted in identifying viable inter-regional transmission projects (Pfeifenberger et al. 2015). Others note that Order 1000 has resulted in a wide variance of cost allocation methodologies because FERC left cost allocation to RTOs and individual transmission owners (Edelston 2015).

Transmission also figured prominently in two legal proceedings. The Seventh Circuit Court of Appeals upheld FERC's requirement in Order 1000 that transmission owners remove the right-of-first-refusal provisions for building new transmission from their transmission tariffs (U.S. Court of Appeals 2016). In April 2016, DOE announced it will use its authority under Section 1222 of the Energy Policy Act of 2005 (EPAct) to participate in the development of a planned Clean Line Energy Partners LLC transmission project, known as the Plains and Eastern project, that would stretch from western Oklahoma to eastern Arkansas (DOE 2016). If developed, the project could transmit up to 4,000 MW. This is the first time that the DOE is utilizing its authority under EPAct to participate in the development of a transmission project.

9. Future Outlook

With the 5-year extension of the PTC signed in December 2015 and IRS guidance allowing a safe-harbor period of 4 years in which to complete construction, but with progressive reductions in the value of the credit for projects starting construction after 2016, annual wind power capacity additions are projected to continue at a rapid clip for several years, before declining. Near-term additions will also be driven by improvements in the cost and performance of wind power technologies, which continue to yield very low power sales prices. Growing corporate demand for wind energy and state-level policies play important roles as well, as might utility action to proactively get out ahead of possible future CPP compliance obligations.

Among the forecasts for the domestic market presented in Figure 54, expected capacity additions average more than 8,000 MW/year from 2016 to 2020, somewhat higher than the pace of growth witnessed since 2007. With AWEA (2016b) reporting that more than 15,000 MW of wind power were under construction or at an advanced stage of development at the end of the first quarter of 2016, the industry appears to be on track to meet these expectations at least in the early years.



Source: AWEA (historical additions), individual forecasts, DOE 2015 (Wind Vision)

Figure 54. Wind additions: historical installations, projected growth, DOE *Wind Vision* report

Forecasts for 2021 to 2023 show a downturn in additions as the PTC progressively delivers less value to the sector. Expectations for continued low natural gas prices, modest electricity demand growth, and lower near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and competition from solar energy in certain regions of the country. At the same time, declines in the price of wind energy over the last half decade have been substantial, helping to improve the economic position of wind even in the face of low natural gas prices. The potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and state RPS requirements. EPA's Clean Power Plan, depending on its ultimate fate, may also create new markets for wind. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse underlying potential trends, wind capacity additions, especially after 2020, remain deeply uncertain.

In 2015, the DOE published its *Wind Vision* report (DOE 2015), which analyzed a scenario in which wind energy reaches 10%, 20%, and 35% of U.S. electric demand in 2020, 2030, and 2050, respectively. Plotted in Figure 54 are the annual gross wind additions from 2014 through 2023 analyzed by the DOE in order to ultimately reach those percentage targets. As shown, actual and projected wind additions from 2014 through 2020 are consistent with the pathway envisioned in the DOE report. Projected growth from 2021 through 2023, however, is well below the *Wind Vision* pathway. As discussed in DOE (2015), and as further suggested by these comparisons, achieving 10%, 20%, and 35% wind energy on the timeframe analyzed by the DOE is likely to require efforts that go beyond business as usual expectations.

Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions in the United States (as well as certain details on the underlying wind power projects) largely come from AWEA (2016a). We thank AWEA for the use of their comprehensive wind project database. Annual wind power capital investment estimates derive from multiplying these wind power capacity data by weighted-average capital cost data, provided elsewhere in the report. Data on non-wind electric capacity additions come from ABB Ventyx's Velocity database, except that solar data come from GTM Research. Information on offshore wind power development activity in the United States was compiled by NREL.

Global cumulative (and 2015 annual) wind power capacity data come from Navigant (2016a) but are revised to include the U.S. wind power capacity used in the present report. Wind energy as a percentage of country-specific electricity consumption is based on year-end wind power capacity data and country-specific assumed capacity factors that come from Navigant (2016a), as revised based on a review of EIA country-specific wind power data. For the United States, the performance data presented in this report are used to estimate wind energy production. Country-specific projected wind generation is then divided by country-specific electricity consumption. The latter is estimated based on actual past consumption as well as forecasts for future consumption based on recent growth trends (these data come from EIA).

The wind power project installation map was created by NREL, based in part on AWEA's database of projects. Wind energy as a percentage contribution to statewide electricity generation is based exclusively on wind generation data divided by in-state total electricity generation in 2015, using EIA data.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO, RTO, or utility. Only projects that were active in the queue, but as yet built, at the end of 2015 are included. Suspended projects are not included in these listings. Data on projects that are in the nearer-term development pipeline comes from ABB (2016), AWEA (2016b), and EIA (2016c).

Industry Trends

Turbine manufacturer market share data are derived from the AWEA wind power project database, with some processing by Berkeley Lab.

Information on wind turbine and component manufacturing comes from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on U.S. nacelle assembly capability come from Bloomberg NEF (2015a) and AWEA (2016a), while U.S. tower and blade manufacturing capability come from AWEA (2016a). The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports (where necessary, focusing only on the wind energy portion of each company's business).

Data on U.S. imports and exports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. International Trade Commission (USITC), and they can be obtained from the USITC's DataWeb (http://dataweb.usitc.gov/). The analysis of USITC trade data relies on the "customs value" of imports as opposed to the "landed value" and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report.

Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis

HTS Code	Description	Years applicable	Notes
8502.31.0000	wind-powered generating sets	2005-2015	includes both utility-scale and small wind turbines
7308.20.0000	towers and lattice masts	2006-2010	not exclusive to wind turbine components
7308.20.0020	towers and lattice masts - tubular	2011-2015	virtually all for wind turbines
8501.64.0020	AC generators (alternators) from 750 to 10,000 kVA	2006-2011	not exclusive to wind turbine components
8501.64.0021	AC generators (alternators) from 750 to 10,000 kVA for wind-powered Generating sets	2012–2015	exclusive to wind turbine components
8412.90.9080	other parts of engines and motors	2006-2011	not exclusive to wind turbine components
8412.90.9081	wind turbine blades and hubs	2012–2015	exclusive to wind turbine components
8503.00.9545	parts of generators (other than commutators, stators, and rotors)	2006-2011	not exclusive to wind turbine components
8503.00.9546	parts of generators for wind-powered generating sets	2012–2015	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014-2015	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[73]

As shown in the table, some trade codes are exclusive to wind, whereas others are not. As such, assumptions are made for the proportion of wind-related equipment in each of the non-wind-specific HTS trade categories. These assumptions are based on: an analysis of recent trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with USITC and AWEA staff; USITC trade cases; and import patterns in the larger HTS trade categories. The assumptions reflect the rapidly increasing imports of wind equipment from 2006 to 2008, the subsequent decline in imports from 2008 to 2010, and the slight increase from 2010 to 2012. To reflect uncertainty in these proportions, a ±10% variation is applied to the larger trade categories that include wind turbine components for all HTS codes considered, except for nacelles shipped under 8503.00.9560. For nacelles, the variation applied is ±50% of the total estimated wind import value under HTS code 8503.00.9560.

[73] This was effective in 2014 as a result of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blade assembly which are essential to wind-powered generating sets as defined in the HTS.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from AWEA and Chadbourne and Park LLP. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of the AWEA project database.

Wind Turbine Technology Trends

Information on turbine hub heights, rotor diameters, specific power, and IEC Class was compiled by Berkeley Lab based on information provided by AWEA, turbine manufacturers, standard turbine specifications, Federal Aviation Administration data, web searches, and other sources. The data include only projects with turbines greater than or equal to 50 kW that began operation in 1998 through 2015. Some turbines—especially in 2015—have not been rated within a numerical IEC Class, but are instead designated as Class "S," for special. In such instances, they were not included in the reported average fleet-wide IEC class over time. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

Performance, Cost, and Pricing Trends

Wind project performance data were compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), PJM, NYISO, SPP (for the Great Plains states), ISO-New England, and BPA (for the Northwest).

The following procedure was used to estimate the quality of the wind resource in which wind projects are located. First, the location of individual wind turbines and the year in which those turbines were installed were identified using Federal Aviation Administration (FAA) Digital Obstacle (i.e., obstruction) files (accessed via ABB Ventyx' Intelligent Map) and FAA Obstruction Evaluation files combined with Berkeley Lab and AWEA data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from average mapped 80-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites). To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100% assigned in that period. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category includes all projects or turbines with an estimated gross capacity factor of less than 40%; the "medium" category corresponds to ≥40%–45%; the "higher" category corresponds to ≥45%–50%; and the "highest" category corresponds to ≥50%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 41,149 turbines of the 41,999 installed from 1998 through 2014 in the continental United States over that period, or 98%.

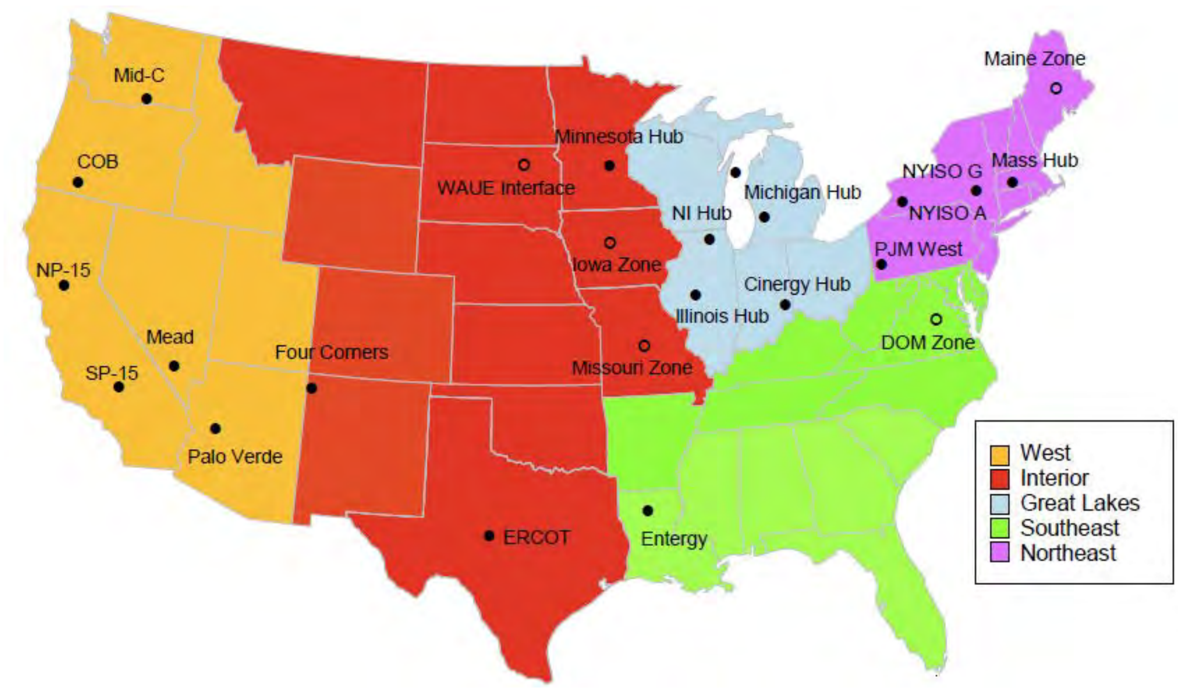
Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange

Commission and other regulatory filings. In part because wind turbine transactions vary in the turbines and services offered, a good deal of intra-year variability in the cost data is apparent. Additional data come from Vestas corporate reports and Bloomberg NEF.

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, the DOE and Electric Power Research Institute Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not equally credible, little emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer insight. Only wind power cost data from the contiguous lower-48 states are included.

Wind project O&M costs come primarily from two sources: EIA Form 412 data from 2001–2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. Some data points are suppressed in the figures to protect data confidentiality.

Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs. Wholesale electricity price data were compiled by Berkeley Lab from the Intercontinental Exchange (ICE) as well as ABB Ventyx's Velocity database (which itself derives wholesale price data from the ICE and the various ISOs). Earlier years' wholesale electricity price data come from FERC (2007, 2005). Pricing hubs included in the analysis, and within each region, are identified in the map below. To compare the price of wind to the cost of future natural gas-fired generation, the reference case fuel cost projection from the EIA's *Annual Energy Outlook 2016* is converted from $/MMBtu into $/MWh using a heat rate of 7 MMBtu/MWh. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.



Note: The pricing nodes represented by an open, rather than closed, bullet do not have complete pricing history back through 2003.

Figure 55. Map of regions and wholesale electricity price hubs used in analysis

Policy and Market Drivers

The wind energy policy and grid integration sections were written by staff at Berkeley Lab and Exeter Associates, based on publicly available information.

Future Outlook

This chapter was written by staff at Berkeley Lab, based largely on publicly available information.

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WIND ENERGY WEBSITES

U.S. DEPARTMENT OF ENERGY WIND PROGRAM
energy.gov/eere/wind

LAWRENCE BERKELEY NATIONAL LABORATORY
emp.lbl.gov/research-areas/renewable-energy

NATIONAL RENEWABLE ENERGY LABORATORY
nrel.gov/wind

SANDIA NATIONAL LABORATORIES
sandia.gov/wind

PACIFIC NORTHWEST NATIONAL LABORATORY
energyenvironment.pnnl.gov/eere/

LAWRENCE LIVERMORE NATIONAL LABORATORY
missions.llnl.gov/energy/technologies/wind-forecasting

OAK RIDGE NATIONAL LABORATORY
ornl.gov/science-area/clean-energy

ARGONNE NATIONAL LABORATORY
anl.gov/energy/renewable-energy

IDAHO NATIONAL LABORATORY
inl.gov

SAVANNAH RIVER NATIONAL LABORATORY
srnl.doe.gov/energy-secure.htm

AMERICAN WIND ENERGY ASSOCIATION
awea.org

DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY
dsireusa.org

INTERNATIONAL ENERGY AGENCY – WIND AGREEMENT
ieawind.org

NATIONAL WIND COORDINATING COLLABORATIVE
nationalwind.org

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Exhibit PHM-10

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	
Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT	Docket No. 40161
Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan	Docket No. 40162

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2016 Integrated Resource Plan (the "2016 IRP") and the Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2016 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

1. The 2016 IRP is approved as amended by this Stipulation.

2. Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1CT and Intercession City CT shall be decertified and retired as provided for in the 2016 IRP.

3. The Renewable Energy Development Initiative ("REDI") is approved and shall be increased such that it will procure 1,200 MW (150 MW of Distributed Generation ("DG") and 1,050 MW of utility scale resources). Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP will be issued to the marketplace in 2017 and will seek 525 MW of renewables with in service dates of 2018 and 2019. The second RFP will be issued to the marketplace in 2019 and will seek 525 MW of renewables with in service dates of 2020 and 2021. No more than a total of 300 MW of wind resources shall be procured through REDI. Bid fees for the utility scale solicitation shall be set at five thousand dollars ($5,000) or three hundred dollars per MW

($300/MW), whichever is greater. The cost to implement and administer the REDI program shall be recovered through the fuel clause. Provided, however, that any costs recovery related to the ASI Prime Program in excess of ongoing ASI Prime costs shall be allocated to REDI and shall not be recovered through the fuel clause. All bid fees collected will be credited to the fuel clause.

4. In 2017, the Company shall issue an RFP for 100 MW of DG greater than 1kW but not more than 3 MW with a commercial operation date of 2018 or 2019. Contract terms will be up to 35 years and solar DG projects must interconnect at Georgia Power's owned distribution system. Bid fees for the DG solicitations shall be set at $4/kW.

5. By the end of 2018, the Company shall procure an additional 50 MWs of customer sited DG projects. Such projects shall be greater than 1kW but not more than 3 MW and must have an installed DC capacity that is less than or equal to 125% of the actual annual peak demand of the customer's Premises in 2015 and be a current GPC customer at the time of award. Procurement shall be done through an application process and if oversubscribed, a lottery will be conducted. Participant fees for the DG solicitations shall be set at $3/kW. Any MWs that are unsubscribed from the customer sited program shall be allocated to the DG RFP reserve list. Customer sited projects will be paid avoided costs using the process as described below in item 8(a).

6. The specific process that will be utilized for the evaluation (such as whether to use a project and/or portfolio analysis) for projects submitted into REDI will be finalized during the review and approval of the REDI RFP documents.

7. The Renewable Cost Benefit framework ("RCB") as provided in paragraph 8(a) shall be utilized in the evaluation of bids received through the REDI RFPs for utility scale and DG projects. The Company and Staff will work collaboratively to develop a process and recommendations for the continued implementation of RCB. Within (4) months from the issuance of the Final Order in this case, the Company and Staff will file their proposal with the Commission for implementation of RCB. If an agreement is reached between the Company and Staff on implementation of RCB, the Company and Staff can recommend to the Commission utilization of the full RCB in REDI.

8. The RCB shall be modified for use in the REDI program as follows:

(a) The Company shall evaluate the bids received in response to REDI RFPs using the RCB. The evaluation of REDI proposals will be limited to the consideration of Avoided Energy and Deferred Generation Capacity cost components consistent with the Framework methodology. Further, the Company will evaluate the appropriate transmission and distribution costs and benefits on a case by case basis as proposed in the Framework document.

(b) Once the evaluation in 8(a) is concluded the Company will conduct, for information purposes only, an evaluation using the entire RCB as filed by the Company to allow Staff and the Independent Evaluator ("IE") to gain familiarity with the RCB. The evaluation will include all aspects of the Framework including specifically, Generation Remix, Support Capacity, and Bottom Out Adjustments. The Company will file its results with the Commission.

9. The Additional Sum for utility scale resources procured through REDI shall be set at 8.5% of shared savings. This amount shall be levelized and recovered annually for the term of the PPA.

10. The Company's closed ash pond solar demonstration project is approved as filed by the Company. The Company will be required to file quarterly construction monitoring reports and will be required to demonstrate the reasonableness and prudency of any recovery in excess of the budget for this project filed in the 2016 IRP. The Simple Solar program is approved with the modifications to the sourcing of the program as recommended by Staff.

    In addition, the Company's High Wind Study is approved as filed. The Company agrees to file quarterly reports providing the status of the High Wind Study. The Staff and Company will collaborate on what, if any, information from the wind study will be made available to interested parties.

11. The Commission approves an additional 200 MW of self-build capacity for use by the Company to develop additional renewable projects in collaboration with customers, including potential projects at Robins Air Force Base and Fort Benning. The projects must be at or below the Company's avoided costs. No more than 75 MW of the 200 MWs provided for in this provision may be used for non-military customer projects. For the non-military customer projects, the Company must demonstrate that the project meets a special public interest need and could not reasonably be achieved using the competitive bid process. The RECs for the non-military customer projects shall accrue to the benefit of all customers.

12. The Company shall consider the development of a renewable Commercial and Industrial Program. No more than 200 MW shall be allocated for such a program and such program must be approved by the Commission before implementation. The Company shall only consider program options that will result in delivering value to all of its customers and will benchmark such programs to the last accepted proposal from the Company's utility scale REDI program.

13. Staff and the Company shall work together to address retirement study and other modeling issues. This process should begin within six months of the final order being issued in this proceeding and must conclude at least 12 months prior to the Company's filing of the 2019 IRP.

14. For purposes of the Company's IRP evaluations the long term Southern System planning reserve margin shall be raised to 16.25%. The Company shall meet with Commission Staff within 6 months of a final order in this case to discuss the timing of future Expected

Unserved Energy studies. The Company will report to Staff once all operating companies have approved for utilization the long term planning reserve margin adopted by this provision.

15. The Company agrees to minimize all capital expenditures on Plant McIntosh Unit 1 and Plant Hammond Units 1-4 through July 31, 2019. The Company agrees to annual limits on all capital expenditures of $1 million for McIntosh 1 and $5 million for Hammond 1-4[1]. The Company agrees to make a filing with the Commission prior to incurring expenditures that exceed the annual limit.

16. The measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental and compliance plan as presented in Technical Appendix Volume 2, Summary of Capital Expenditures, Closures, and O&M Expenses filed as part of the 2016 IRP are approved subject to the limits outlined in No. 15 above regarding Plant McIntosh Unit 1 and Hammond Units 1-4. This approval does not preclude the Commission from reviewing prudence of the actual expenditures made to effectuate the compliance plan.

17. The remaining net book values of Plant Mitchell Unit 3 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

18. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate case.

[1] The Hammond Units 1-4 $5 million value represents the cumulative annual amount for all four units. This provision does not apply to expenditures required for retirement obligations.

19. The Company shall report to the Commission concerning progress on the dismantlement and remediation of the Plant Kraft generating plant site and the Company shall provide the Commission with appraised values of any land at that site that the Company would propose to donate to the Georgia Ports Authority, including information regarding whether the appraised value exceeds the Company's net book value of such land.

20. The decision whether to accept, modify or defer consideration of the Company's request for authority to capitalize additional costs to preserve new nuclear shall be a policy decision for the Commission. Adoption of this provision within this stipulation does not preclude any Party from making any argument for or against the Company's request in this regard, nor does this agreement or this provision within this agreement suggest that the Commission must or should (or should not) consider this question as part of this IRP.

21. When filing the 2019 IRP or when filing any updates to the IRP prior to the 2019 IRP filing, the Company agrees to provide the Commission Staff working copies of all models used in the development of that IRP, with each configured to replicate inputs used to derive results incorporated in its base case scenario within 10 days after the IRP or update to the IRP is filed.

22. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed $300,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

23. The Electric Transportation Initiatives and associated costs identified in the 2016 IRP are not, and have not been converted into, jurisdictional expenses that become the responsibility of ratepayers. Each party reserves the right to address these costs and the merits of the program through the Annual Surveillance Report process and future rate cases.

Demand Side Plan

1. The Company's 2016 Demand Side Management ("DSM") Plan and Application for Certification, Decertification and Amended DSM Plan is approved as amended by this Stipulation.

2. Georgia Power will continue to treat DSM as a priority resource in accordance with prior Commission precedent. For the calculation of long term percentage rate impacts, the Company will work with Commission Staff to come up with a methodology within 12 months of the issuance of the final order.

3. Georgia Power will enter discussions over the next three years with Staff and DSMWG members on the value of a Residential Mid-Stream Retail Products Program.

4. Georgia Power will develop a Technical Reference Manual prior to the Company's next IRP filing and will update it every three years thereafter. The Company will work closely with Staff and members of the DSMWG and DSMWG members may also propose new measures to be added at any point in the measure evaluation process. The DSM Program Planning Approach filed as Staff Exhibit BSK8 will otherwise remain unchanged other than "Technology Catalog" will be replaced with "Technical Reference Manual" and the dates will be updated to reflect 2017 through 2019.

5. Georgia Power will agree to the budget adjustments as provided in exhibit 8 attached to this Stipulation as amended.

6. Georgia Power will receive an Additional Sum equal to 8.5% of actual net benefits based on net energy savings from the Program Administrators Cost Test ("PACT"). Once the Additional Sum amount as calculated exceeds the annual program costs, the portion of the Additional Sum that exceeds the program cost shall be calculated based on 4% of the actual net benefits based on net energy savings from the PACT.

7. Georgia Power will work with Staff and the Company's implementation contractor for the Residential Behavioral Program to find ways to include more customers in the program.

8. The Company will make a concerted effort to obtain at least 25% of portfolio savings each year from the Residential sector.

9. Once a program implementer is selected and plans for all proposed programs are drafted and completed, the plans will be provided to Staff for review prior to implementation of the programs. The current review and approval process reached in an agreement between Staff and the Company in 2014 will continue, and the Company agrees to discuss further refinements and revisions to the process. In order to change the process both Staff and the Company must agree to the recommended changes.

10. The Company will provide detailed evaluation plans for each of the approved DSM programs within 120 days of the selection of Program Implementers for each of the certified programs. If necessary, the Company may request, and Staff may unilaterally grant, additional time to complete the detailed evaluation plans for each of the approved DSM proposals.

11. The Company will agree to a Commercial and Residential Building Usage Data awareness option at the cost of $300,000 for 2017 and $100,000 annually for 2018 and 2019, and such costs will be added to the DSM Consumer Awareness budget. This option will be available to customers within one year from the date of the final order in

this docket. There will be no assumed energy savings or goals attributed to this customer awareness option.

12. The Company and Staff agree to a $2.5 million annual pilot budget for DSM and energy efficiency pilot programs. Staff will be notified before the start of such pilots.

13. The Company agrees to the Staff recommendation for the Learning Power program annual budget to be $3 million.

14. The Company agrees to the Staff recommendation against shifting residential and commercial customer awareness to cross-cutting costs.

15. The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

[Additional Signatures]

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On behalf of Clean Line Energy Partners LLC
David Berry
authorized person

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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[Additional Signatures]

Chas. B. Jones, III
On behalf of Georgia Association
Of Manufacturers

On behalf of Georgia Industrial
Group

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

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Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

On behalf of Georgia Industrial Group

[Additional Signatures]

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On behalf of The Georgia Large
Scale Solar Association

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

[Additional Signatures]

On behalf of Georgia State Building and Construction Trades Council

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

[Additional Signatures]

Bruce W. Burcat

On behalf of Southern Wind Energy Association