White Paper

Building the Bridge to a Merchant Solar Future

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Shareables:

- Some analysts are projecting the cost of PV Solar to reach as low as $\$1/W_{dc}$ by 2020
- Under ICF Assumptions an additional 41 GW of PV solar could be added by 2045
- Natural gas prices increases could raise power prices by up to $17/MWh by 2030, making the path for merchant solar easier.

The Path So Far

Solar PV is edging beyond the Power Purchase Agreement (PPA) platform and into the merchant market as the driver for growth. Historically, PV project development has been driven by utilities issuing PPAs to meet mandated state renewable requirements. However, many states are already hitting or on track to meet their Renewable Portfolio Standard (RPS) targets. In addition, steep declines in solar capital costs and technology improvements have affected PV power economics and PPA pricing significantly. Solar PPA prices have decreased every year since 2006 and have fallen by more than two-thirds since 2009.[1] As a result, solar developers will be looking to new growth drivers for the PV space. As solar costs approach $1/watt and continue to decline, merchant solar will grow, especially in regions with better solar resources.

[1] PPA prices referenced above have been levelized over the full length of the contract and translated into real 2014$, such that a contract without an inflator would decrease over time in real dollars.

Lower capital cost, enhanced PV performance, increasing projected natural gas price and carbon regulations are closing the gaps between the cost of solar energy and the market price. Additionally, battery integration has the potential to close the gap even further.

Where is the Demand for PV?

The U.S. installed 20 GW of utility-scale PV through 2016. The solar installed capacity almost doubled in 2016, with the majority of that coming from projects procured by utilities to meet state-level mandatory and voluntary RPS requirements. But with many states meeting, or on track to meet, their RPS requirements, and with PPA prices in some areas now ranging between $40 and $60/MWh, utility PV's value proposition should be evolving beyond simply meeting an RPS obligation.

The majority of states fully met their interim RPS targets over the last three years, with the exception of Illinois, New Mexico, and states in the Northeast. Most states that fully achieved those targets are well ahead of their solar/distributed generation targets. Compliance with solar carve-outs within RPS targets averaged 86% in 2015.[2] If this progress in achieving targets continues, a significant demand driver for PV will fade away, and new PV growth will be driven only by incremental growth in energy demand, which has been quite low in recent years.

Bridging the LCOE Gap

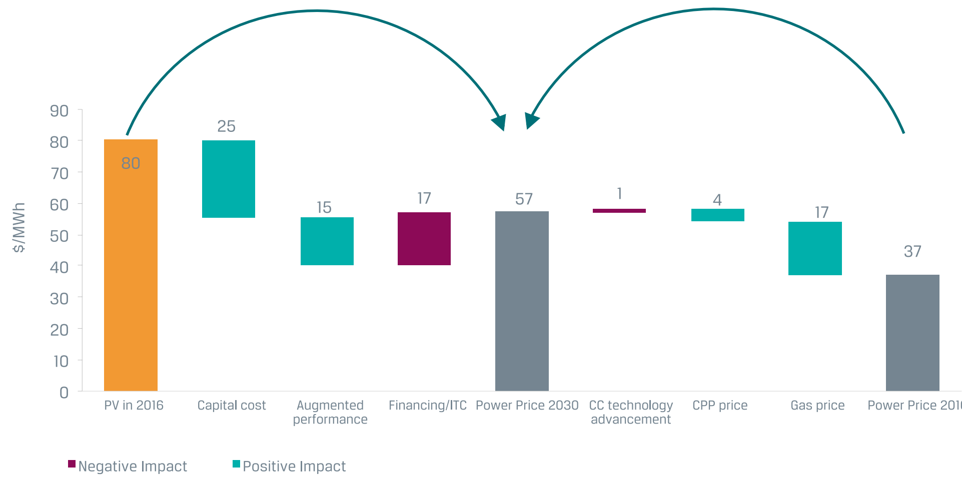
Exhibit 1 illustrates one path to merchant solar viability by 2030, with technology cost declines from the left meeting energy price increases from the right. It shows that achieving grid parity will rely on the alignment of a number of moving pieces but that it is achievable, even in those areas where PV is currently out of the money.

Starting from the solar cost perspective, capital costs of PV are assumed to fall to $1/W_{dc}$ by 2030, lowering the levelized cost of energy (LCOE) for utility scale solar by $25/MWh. Improvements in PV performance are further anticipated to help decrease the PV LCOE by $15/MWh. However, with the ITC being reduced to 10% by that time, some of this cost decline will be offset.

On the power market price side of the equation, we expect increasing natural gas prices to raise power prices to $17/MWh by 2030. Some form of carbon price will further close the gap by increasing power prices by around $4/MWh. Softening the power market increase somewhat will be technological improvements in combined cycle technology, but those will have only a mild negative impact on price.

[2] Source: U.S. Renewables Portfolio Standards 2017 Annual Status Report, Lawrence Berkeley National Laboratory. July 2017

EXHIBIT 1: BRIDGING THE GAP BETWEEN LCOE AND MARKET POWER PRICE BY 2030



Source: ICF

The analysis in Exhibit 1 suggests that the key to bridging the money gap will be a combination of many interactions. The remainder of this paper discusses those interactions in greater detail.

Chasing Gas Prices: Solar Costs Decline, But Is It Enough

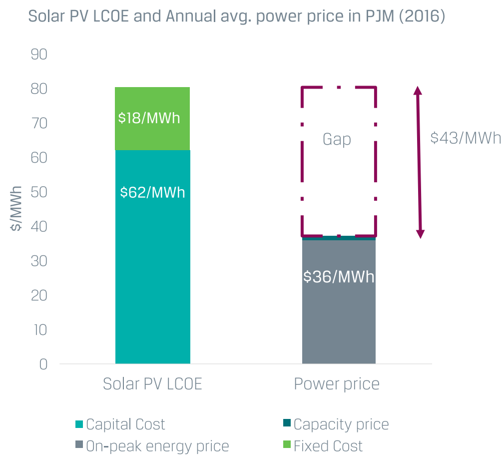
With lower capital costs, improving capacity factors and extension of federal investment tax credit (ITC) incentives, PPA prices for utility-scale PV have declined over time. Prices declined by approximately $25/MWh per year, on average, from 2006 through 2013. The rate of decline has stabilized more recently, however, averaging approximately $10/MWh between 2014 and 2015.[3] Resulting PPAs in the Southwest states have been priced as low as $40/MWh in absolute terms.[4]

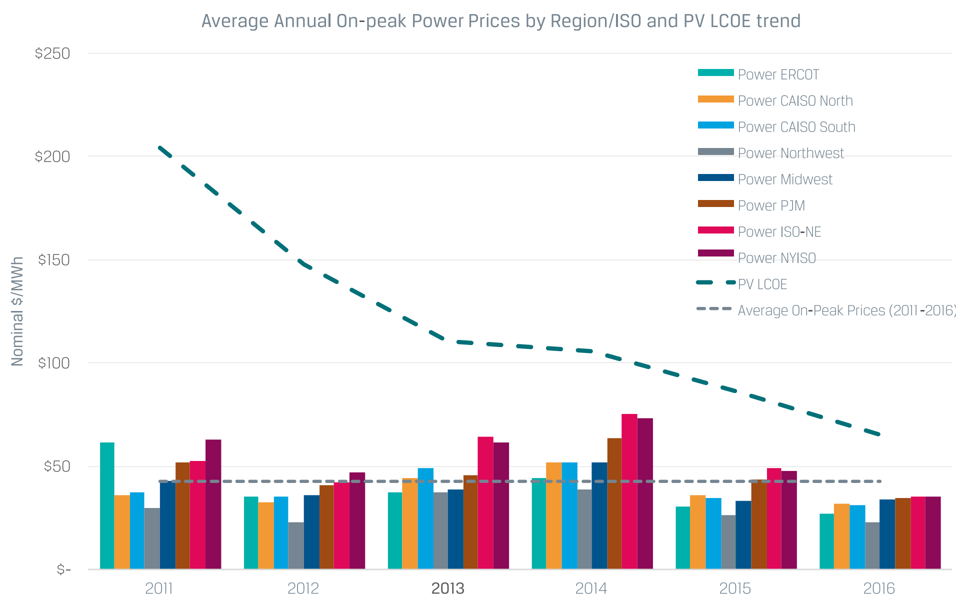
Despite the cost declines, PV still has a sizable gap to fill before it will compete on a purely merchant basis. In most regions, wholesale market peak prices that could be realized by a merchant solar facility have also declined due to low gas prices and other factors, and remain well below PV costs. The graphic on the right in Exhibit 2 below compares the LCOE of utility-scale solar with the annual average on-peak energy prices in different ISOs over the past six years. While the "US average LCOE of solar PV" has dropped significantly, wholesale market prices have also declined, leaving merchant solar uneconomic for the time being.

[3] *Utility-Scale Solar 2014* - Project Cost Performance and Pricing Trends in the United States; Lawrence Berkeley Lab, 2015

[4] The first reported contract for solar power under five cents per kWh occurred in 2014: Austin Energy's 25-year PPA with SunEdison for 150 MW of solar power. The trend continued in 2015, when Nevada Energy secured a 4.6 cent per kWh PPA with SunPower. The solar portion of a solar plus storage PPA with Tuscon Electric Power in May of 2017 is reported at approximately $30/MWh.

EXHIBIT 2: SOLAR PV LCOE AND ENERGY PRICES IN MARKET





Source: SNL & ICF

The graphic on the left in Exhibit 2 compares the LCOE of a typical utility-scale merchant solar plant with the annual average energy price that a solar PV project would have realize in the PJM region in 2016.[5] Even with the benefit of a 30% ITC, merchant solar still faces a looming gap of $43/MWh. Surprisingly, given the well-publicized cost declines for PV, realized energy prices dropped further, widening this gap. This gap varies widely by region due, in large part, to solar insolation and energy price differences. For example, while not explicitly shown, Arizona is close to being economic due to the locational advantage of having higher solar insolation compared to most regions in the US.

[5] For this particular LCOE calculation, we assume a fixed tilt solar PV configuration with annual average capacity factor of 18%, a flat fixed operation and maintenance cost of $29/kW-yr, a capital cost of $1.15/$W_{dc}$ and a capital charge rate (i.e., an annuity rate) of 11%.

PV Costs Will Continue to Decline

As noted above, there has been very rapid reduction in the cost of solar generation between 2007 and 2016 with an average decline of approximately 13 percent per year. Some analysts are projecting the cost to reach as low as \$1/W_{dc} by 2020 for single-axis tracking.[6] A drop from \$1.5/W_{dc} to \$1/W_{dc} would lower the LCOE by approximately \$23/MWh, filling some of the gap between PV cost and market prices.

Furthermore, economies of scale continue to play a big role in bringing down the capital costs at the utility scale. Large-scale solar projects (those > 50 MW) can achieve significant economies across hard/soft cost categories compared to smaller projects (those between 5 – 10 MW), with as much as a 30% build cost savings. Currently, hard costs, such as modules, do not exhibit as strong of economies as soft costs. However with hard costs representing approximately 55% of total cost, lower future costs have great potential to come down further.[7]

Improved cell efficiency, better tracking, and increased inverter loading ratio can be important factors in lowering PV's LCOE. Single-axis tracking improves the average capacity factor by 3% to 4% over projects that used fixed-tilt racking.[8] A 1% increase in capacity factor lowers LCOE by \$4/MWh. An increase in the inverter loading ratio is another strategy for improving performance. Higher inverter loading means adding more panels to the array but keeping the same size inverter, improving the array's average AC capacity factor between 1% and 6%, depending on the solar resource. However, this improved performance comes at additional fixed costs.

Challenges: Are Recent Market Trends and Structure Changes Helping?

While cost reductions are bringing merchant solar closer to reality, several market movements are pushing in the other direction.

Financing – The Drawdown of Support

Federal and state policies of ITC, MACRS, and RPS have provided strong incentives for the PV market, but the economics for PV will be a setback with ITC fading to lower support levels. Congress passed an extension of the ITC in 2015, but the credit will be reduced from its current 30% level to 10% by 2022. This reduction will effectively increase PV's LCOE by approximately \$20/MWh. Going merchant, solar PV will also certainly have higher costs of capital requirements to compensate for the higher risk exposure.

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[6] In some locations PV is approaching \$1/W_{dc} for a fixed tilt system today.

[7] Additionally, smart procurement strategies of spreading the PV component purchases such as panels in phases instead of a bulk purchase can also prove beneficial as it can potentially capture further market declines or hedge against possible import tariffs.

[8] http://www.utilitydive.com/news/utility-scale-solar-booms-as-costs-drop-challenging-gas-on-price/406692/

Fuel Costs – Continued Delays in Gas Price Recovery

Natural gas prices are one of the major drivers of electricity prices in many markets. Gas prices remain low as the markets try to work off excess supply from the Marcellus shale. While NYMEX futures put 2023 pricing at around the $3.0/MMBtu level (only slightly above recent lows of $2.5/MMBtu seen in 2016), ICF projects that gas prices will increase to about $4.0/MMBtu over that same time period. The $1.0/MMBtu difference would translate to over $9/MWh in many markets, improving merchant solar's outlook.

Potential for More Nuclear and Coal Subsidies Could Slow Down Baseload Retirements

Excess capacity and low energy margins due to the cheap natural gas are driving nuclear and coal plants towards retirement. It is expected that an additional 4.2 GW of coal and 6.7 GW of nuclear capacity will shut down by 2026. However, recent state programs from New York and Illinois on "zero-emission credits" have been recently upheld in court. Ohio, New Jersey, and Connecticut are also trying to establish their own programs. Furthermore, the Trump Administration may consider extending a helping hand to these "at risk" plants.[9] Lifelines for that capacity may also cause delays in the economic penetration of PV.

Solar Wars

Finally, after hearings of complaints by Suniva and SolarWorld, the Investment Tax Credit (ITC) will make a decision on whether to proceed with import tariffs for solar panels by September 22, 2017.[10]

Climate Policy Delays – Lack of Carbon Pricing in the Market

In March of 2017, the President signed an executive order directing the EPA administrator to dismantle the Clean Power Plan. Nevertheless, there is still a possibility that we will see some type of national program on carbon in the back-end of the next 10 years, or see more states or regions with carbon programs like California's AB32 or the northeast's Regional Greenhouse Gas Initiative (RGGI). California's most recent auction last May produced carbon prices at almost $14/ton. Depending on the region, these carbon price levels could translate into energy prices as high as $14/MWh in coal-dominant regions, or $6/MWh in gas-dominated regions.

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[9] The DOE report has been released in early September 2017. While there was growing concern about fuel assurance and acknowledgement of a host of policy issues negatively impacting baseload nuclear and coal assets, there is no immediate relief for these fuel-assured power plants.

[10] The companies are asking for a tariff of $0.40/W and a floor price of $0.78/W

Capacity Market Regulations

Things have become more complicated in capacity markets for renewables. With PJM's recently introduced Capacity Performance rules, individual solar generators will pick their own risk exposure as they will be paid the auction clearing price or penalized based on their performance during designated performance assessment hours (PAHs).[11] Thus, in an evolved market like PJM, PV producers are likely to see a reasonable revenue stream in the form of capacity payments if they prudently bid in the capacity markets. One potential strategy for capacity market sellers that own one or more intermittent resources, such as capacity storage resources, demand resources, and energy efficiency resources that are located in the same area, would be able to create and offer an "aggregate resource" for a PJM-approved, unforced capacity value that satisfies the requirements of a Capacity Performance product.[12]

Combined Cycle Technology Improvements

PV is not the only technology that has been evolving. The market's "go-to" fossil technology, the combined cycle plant, has been making improvements as well. In 2016, at least half of the projects going forward were already adopting "state-of-the-art" turbines with improved heat rates of 6,100-6,200 Btu/kWh. Better cycle efficiencies improve the energy margins for combined cycle plants and potentially lower both electricity energy and capacity prices, thereby negatively impacting renewables.

It's a Matter of Time: A Brighter Future for Merchant PV

Despite these challenges, there is a future for merchant solar. Exhibit 3 shows ICF's analysis of the potential for incremental solar penetration using a reasonable set of market assumptions.[13] Under these assumptions, PV penetration in the U.S. relative to a "Business as Usual" case is 8 GW greater in 2025, 28 GW greater in 2035, and 34 GW greater in 2045, with the majority of those additions being driven by merchant economics rather than RPS requirements.[14] Increased market competitiveness of PV makes it the capacity type of choice in some areas, beating out alternatives, including wind and combined cycle plants.

The regions with better solar resources, like the Western Electricity Coordinating Council (WECC), Southwest Power Pool (SPP), and Electric Reliability Council of Texas (ERCOT) areas, see larger solar penetration changes over the years than other regions. WECC will still be the hregion with the highest PV penetration in the US market, with about 19% of the capacity from solar PV in 2045.

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[11] http://www.pjm.com/~/media/markets-ops/rpm/20150708-capacity-performance-webex-training.ashx

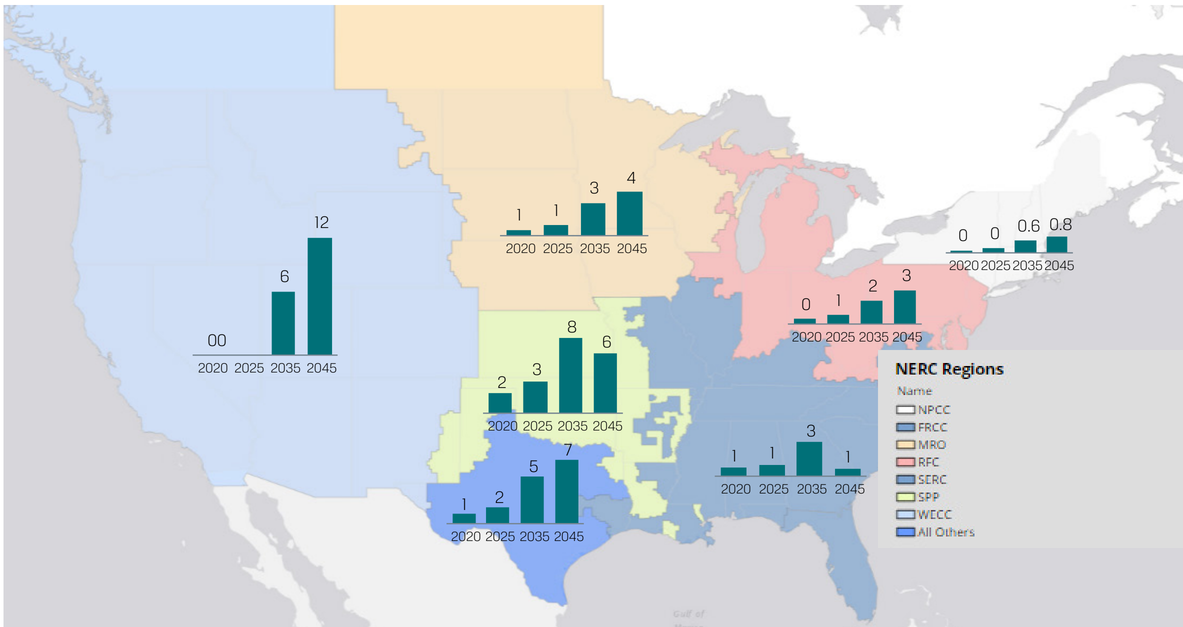
[12] https://www.pjm.com/~/media/documents/manuals/m18.ashx

[13] We assume a slightly faster decline in capital costs and also a slight improvement in capacity factor.

[14] Both the BAU and the alternative future case track mandatory and voluntary RPS requirements.

The steep increase in penetration between 2025 and 2035 is due to further improvements in technology performance (e.g., solar panel efficiency improves and increased applications of dual-axis tracking systems) and reductions in capital cost (e.g., further panel cost reductions and larger plant sizes). Due to this increased solar PV penetration, energy prices fall and some new combined cycles will be replaced.

EXHIBIT 3: CUMULATIVE DIFFERENCE IN SOLAR PV PENETRATION 2020 – 2045 (GW)



Source: SNL, NERC & ICF

Next Steps for PV - Enhancing Value through Battery Storage

Even with the lower cost and better performance, without a way to save electricity for later use, intermittent solar may still struggle to close cost and performance differences with fossil fuel generation in certain regions of the US. The "Duck Curve" peak load shifting challenge seen in CAISO is inevitable given the generation profile for solar PV, and so is the migration of the issue to other regions. However, integration with battery-based storage could resolve solar PV's shortcomings in this area and create additional value. Stay tuned!

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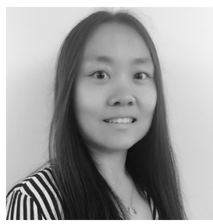

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