THE SOL SOURCE

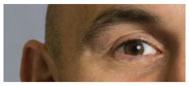
BIFACIAL OR BUST?

Engineering Solar Financings of the Future: p5

SOLSYSTEMS

WELCOME

THE SOL SOURCE is a quarterly journal that our team distributes to our network of clients and solar stakeholders. Our newsletter contains energy statistics from current real-life renewables projects, trends, and observations gained through monthly interviews with our team, and it incorporates news from a variety of industry resources.



STATE MARKETS

Washington DC

On March 22, the DC Council's Clean Energy DC Omnibus Amendment Act became law, making it one of the nation's most aggressive clean energy laws, including a 100 percent renewable portfolio standard (RPS) and a 10 percent solar carve out goal. This law is not only among the strongest of its kind in the United States with the biggest solar carve out, but it also goes into effect the soonest: the District must meet its RPS goal by 2032 and its solar carve-out goal by 2041.

The amount of solar generation located within the D.C. region is expected to skyrocket quite quickly as soon as the legislation goes into effect. As reported by pv magazine, Washington, D.C. generated 52 gigawatt-hours of electricity from solar in 2017, which is equivalent to less than 0.5% of the district's demand. The new law requires that Pepco add 10x as much solar capacity to its generation mix by 2032.

In addition to the RPS and solar carve out goals, the legislation takes swift strides toward decarbonizing Washington, D.C.'s economy writ large: fleet vehicles must meet stringent new emissions standards and commercial buildings must meet Energy Star energy efficiency requirements and other standards based on building size.

This ambitious legislation has major implications for all energy consumers in Washington, D.C., particularly our customers who are commercial real estate owners. Reach out to us for more information about how the new law will impact you, and how Sol Systems can help you to achieve its targets.

Maryland

For the third year in a row, Maryland's state legislature is considering an overhaul and expansion of the state's Renewable Portfolio Standard (RPS). HB 1158/SB 516, the Clean Energy Jobs Act of 2019, increases the RPS goal from 25% to 50% and increases the solar carveout to 14.5%, which is equal to about 5 GW of solar. This is a significant boost from the current 2.5% carveout, and it's sorely needed. The state SREC market is significantly oversupplied, installations are down, and The Solar Foundation's Solar Jobs Census reveals the state lost 800 solar jobs last year, ranking 47th in the United States for job growth.

As of this writing, the legislation has passed the Senate 33-13 with bipartisan support. The bill has now been sent to the House Rules Committee and is awaiting a hearing from the House Economic Matters Committee, which is responsible for reviewing the bill and sending it to the floor.

The bill's chances are unclear. MDV-SEIA's perspective is that political inertia is the bill's greatest foe, as the legislature is also considering other meaty issues this session and lawmakers prefer to space out major bills. At this point, the bill's path to passage appears to be complicated. However, a strong coalition of renewables advocates, environmentalists, faith leaders, and manufacturers have coalesced around the legislation, and if it doesn't pass this year, it will undoubtedly be back (and hopefully better than ever) during next year's legislative session.

Other relevant bills with a chance of passage include a measure requiring the state Public Utilities Commission to create a customer choice website for electricity customers, a bill establishing an energy storage pilot program, and an effort to establish a commission to study solar energy's impacts on land use and farm land.

South Carolina

Last month, the South Carolina Energy Freedom Act (H3659) passed the SC House unanimously and moved to the Senate Judiciary committee for consideration. The committee has held two hearings thus far to hear stakeholder feedback on the measure. The legislation, which is considered a compromise bill between clean energy advocates, the solar industry, and utility companies, extends the state's existing net metering system until June 1, 2021, effectively lifting the net metering cap. When the existing net metering program ends, the state PSC will become responsible for determining net metering rates for solar customers.

Despite efforts to bring all parties to the table to develop a bill that would garner broad support, Duke Energy remains opposed to some bill language related to how large-scale solar projects are contracted under PURPA, instead preferring for the state to shift toward a competitive bidding structure. As written, the bill would enable some queued solar projects to secure 10-year contracts with utilities at future, PSC-approved avoided costs rates.

Those aren't the only changes for large-scale solar projects. If the bill passes, the PSC will be become responsible for determining methods for calculating payments to solar developers that are "commercially reasonable" and compliant with PURPA. It also establishes a new process for interconnecting large-scale solar projects to the grid, which includes PSC enforcement and conflict resolution. Solar developers have complained that hundreds of megawatts of solar projects are backlogged, awaiting interconnection in Duke's territory.

The legislation also increases competition in the energy sector by increasing scrutiny of new utility power generation proposals, launches a renewables program for commercial and industrial energy customers, creates new consumer protections for solar customers, and establishes the framework for a community solar program.

Bifacial or bust? Engineering solar financings of the future

By: Becca Glazer and Kevin Mayer

The solar industry hates stasis, which is exemplified in industry members' self-proclaimed rides on "the Solar Coaster." Solar trade shows and conferences are filled with companies looking to provide solar with its "next big thing." One of solar energy's (literal) shiny new objects - bifacial modules - has been a hot topic at these conferences and in news articles for a few years now. Until recently, however, most of the potential benefit of bifacial modules has remained…potential. However, bifacial modules are starting to transition from theory into reality, as more projects around the world and in the United States specify bifacial modules, reach financing and construction, and begin operation.

We get it. You probably think you've read this story before. You're expecting another article about the existence of bifacial modules (with accompanying diagrams), reviewing how there's some benefit of the technology while expressing a decent amount of uncertainty, and a conclusion of "I guess we'll wait and see what happens with this promising new technology!"

We'll be sure to cover all those standard bases; don't worry. But this time, we'll also dig into the wonky details of how implementing this technology impacts a real structured finance model, how a debt provider's confidence in that energy benefit affects returns, and what you really need out of your bifacial project to generate positive returns. It's time to grab your bifocals and look at (both of) the bright sides.

Introduction to the Technology

Bifacial solar photovoltaic modules produce energy on both sides of the module. Energy is captured on the back of the module by collecting sunlight on its backside that was reflected off the ground.

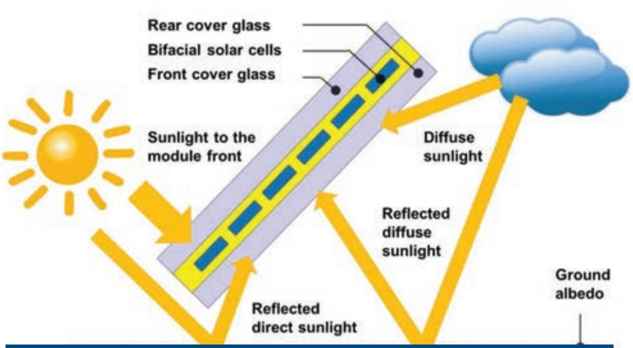


Diagram of a bifacial module (Source: TÜV Rheinland Energy)

There's minimal doubt that there will be some benefit to project performance due to energy from the backside of the module (known as bifacial gain), but the question remains: exactly how much?

While a relatively standardized process for energy modeling has been developed and accepted for monofacial systems, this has not yet happened for bifacial systems. The main roadblock to standardization has been that their implementation greatly increases the importance of a few variables that have a negligible effect on monofacial systems and are thus less well studied, such as albedo (the measure of ground reflectance), and the shading and mismatch created by the racking structure underneath the modules. While a number of field test sites have been installed in the last few months, operational data from those projects to support better energy modeling practices is months away.

Few analyses have looked at how this uncertainty impacts the actual financing of a project. The increase in cost, energy generation, and uncertainty on that energy generation, will affect all three of the main parties in a structured transaction: sponsor equity, debt, and tax equity. We'll examine these impacts first in a general sense, and then through the lens of a real project.

The Juicy Model Details

We'll examine an existing development project with monofacial modules, then assume the substitution of bifacial modules of an equivalent frontside power rating while holding all other project variables constant. We then assume a market-based module cost increase for a project in 2020, as well as an "EPC Adder" taking into account second-order impacts of adding bifacial modules:

TABLE 1

Cost Of Incorporating Bifacial Modules	
Category	Bifacial Cost Adder
Framed Bifacial Module	$0.04/W
EPC Adder (tax, contingency, performance testing complexity)	$0.01/W
Total	**$0.05/W**

When modeling, we used an inverted lease structure with project-level debt, one of several commonly used financing mechanisms for structured solar transactions.

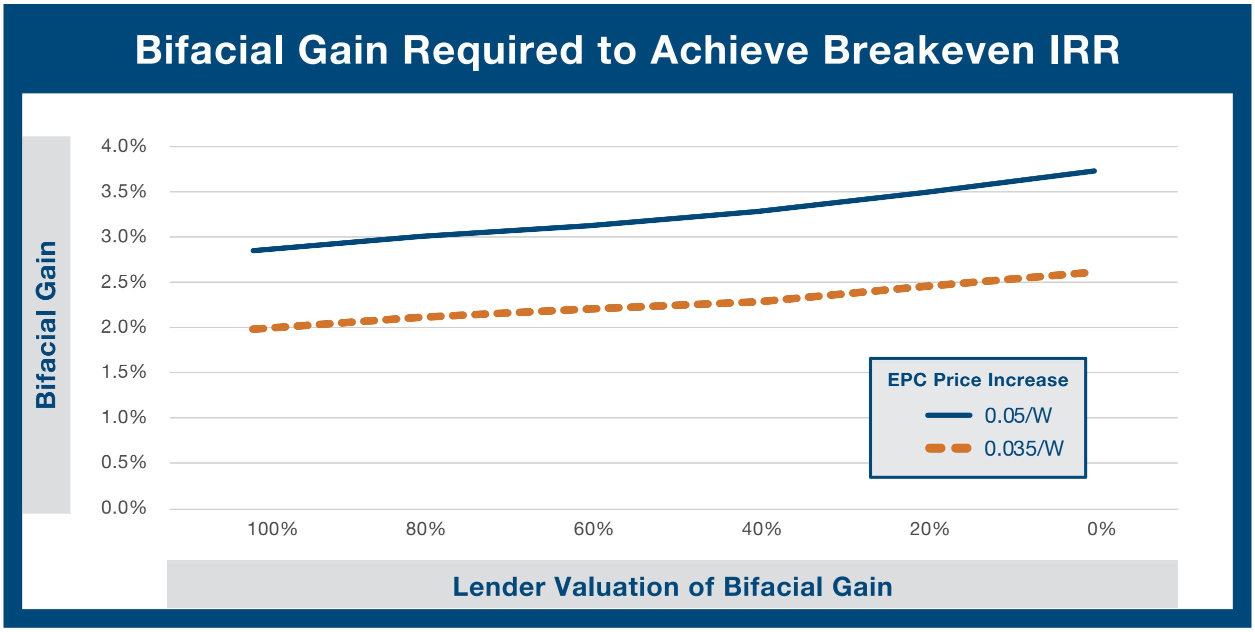
All else being equal, the more debt a project can support, the better the returns because debt is generally the "least expensive" source of capital for a project. Lenders tend to be a risk-averse bunch, but if a lender will value more of the increase in energy yield, this will increase the amount of debt the project can raise. However, debt providers we spoke with suggested they might only value a portion of the modeled bifacial gain given the increased uncertainty and the current lack of available bifacial project performance data.

This means that if a project had a modeled bifacial gain of 8% over an equivalent monofacial project, all else being equal, a lender valuing 100% of that gain could be expected to provide 8% more debt than for the monofacial project. However, a lender valuing only 50% of that 8% gain may only provide an additional 4% more debt. This lender valuation variable is intended to illustrate the additional energy production uncertainty for bifacial projects. In order to make a project work, not only do you need enough modeled bifacial gain, that gain needs to be supported by sufficient certainty to be economically justified.

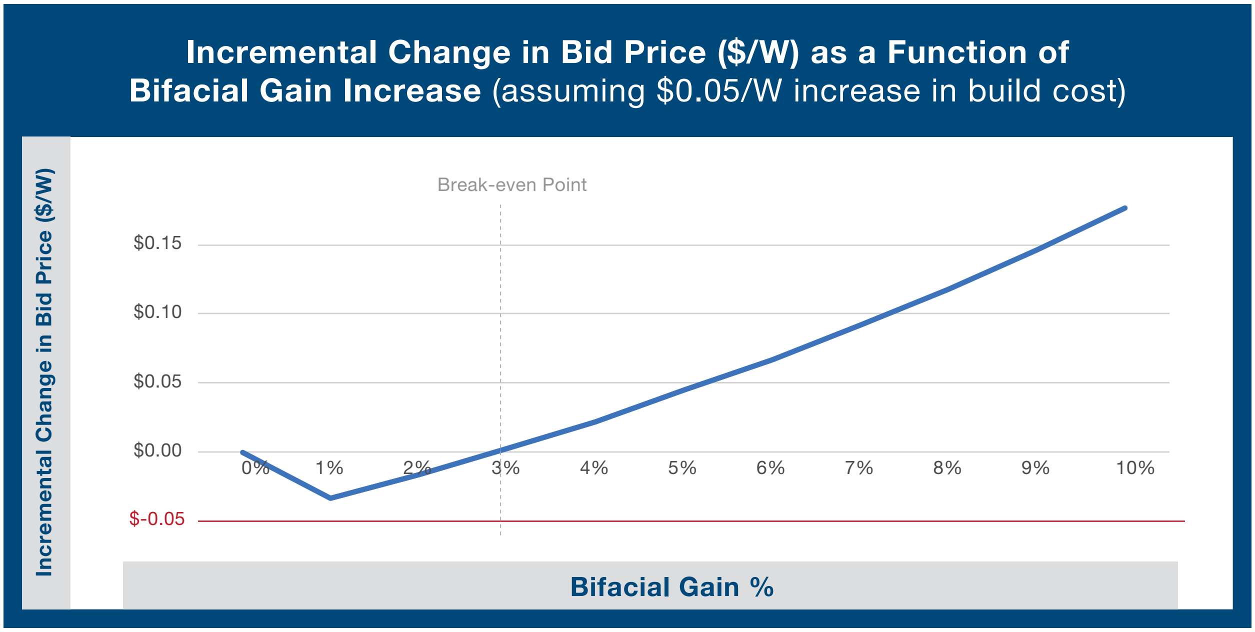
Show Me The Money

Our analysis suggests that for a fixed EPC cost increase of $0.05/W (roughly 5% on a typical utility-scale project that costs about $1.00/W to build), a bifacial gain of above 3-4% results in a more valuable project.

Remember – this is one project, and this analysis depends on some high-level assumptions, so these results will vary significantly project to project. However, the data still tells a compelling story. We calculated a baseline monofacial structured Sponsor IRR. We then ran the model incorporating the cost of adding bifacial modules, and a range of debt valuation of bifacial gain. The graph below shows the incremental increase in bifacial gain required for the project to "break even" by achieving our established benchmark IRR after incorporating bifacial modules. We show this at both our base assumption of a cost increase of $0.05/W, and at a more optimistic $0.035/W cost increase for comparison purposes.



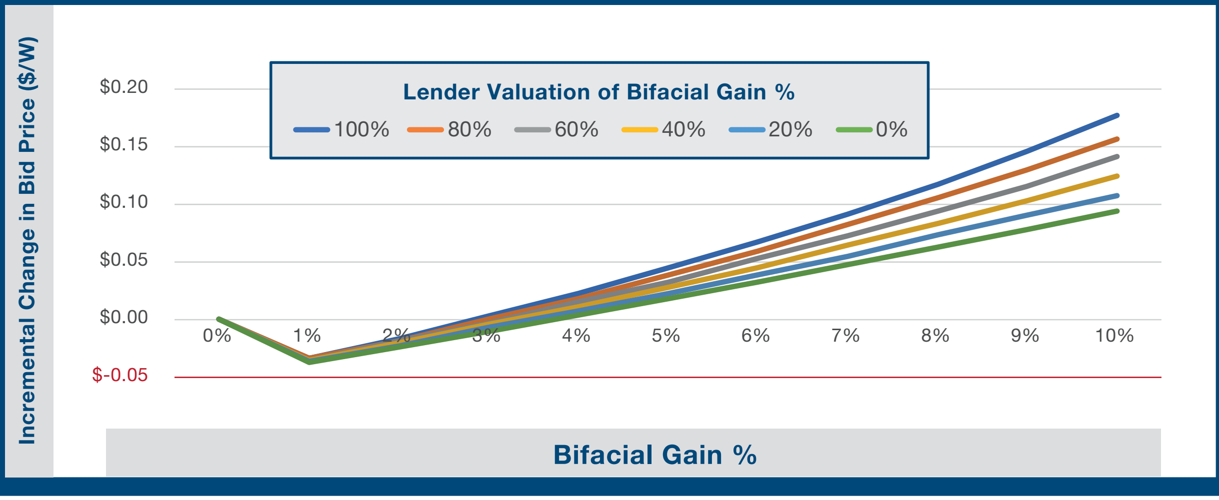
Looking specifically at the case of 100% lender valuation of bifacial gain, anything above this breakeven point of around 3% caused a positive change in a theoretical project acquisition price. This means a bidder strategically valuing bifacial gain could offer a higher price and provide more value to project developers.



Looking at the more complicated case where we recognize the higher uncertainty of bifacial projects and potential variability of lender valuation of bifacial gain, the breakeven point can range from around 3% to nearly 4%.

At a 5% bifacial gain, the value that a lender places on that gain can change the incremental project bid price by nearly $0.03/W. At a higher 10% bifacial gain, this change based on lender valuation leads to an even larger difference of about $0.08/W.

Incremental Change in Bid Price ($/W) as a Function of Bifacial Gain Increase (assuming $0.05/W increase in build cost)



Looking at this another way, a bifacial project where the lender will value 100% of a 7% modeled bifacial gain is just as valuable as a project where the modeled bifacial gain is 10%, but a lender will not value that when sizing the project's debt. This highlights the importance of combining technical accuracy with commercial practicality and the need to reduce uncertainty wherever possible.

For buyers in a market with abundant capital chasing a finite supply of projects, any increase in project debt and subsequent reduction in cost of capital creates a competitive advantage. For developers, there's no need to overstate the importance of any additional cent of margin. This suggests that bifacial modules may no longer be a fancy "upgrade" for projects, but rather an important part of the industry's competitive toolbox.

Let's Get Real

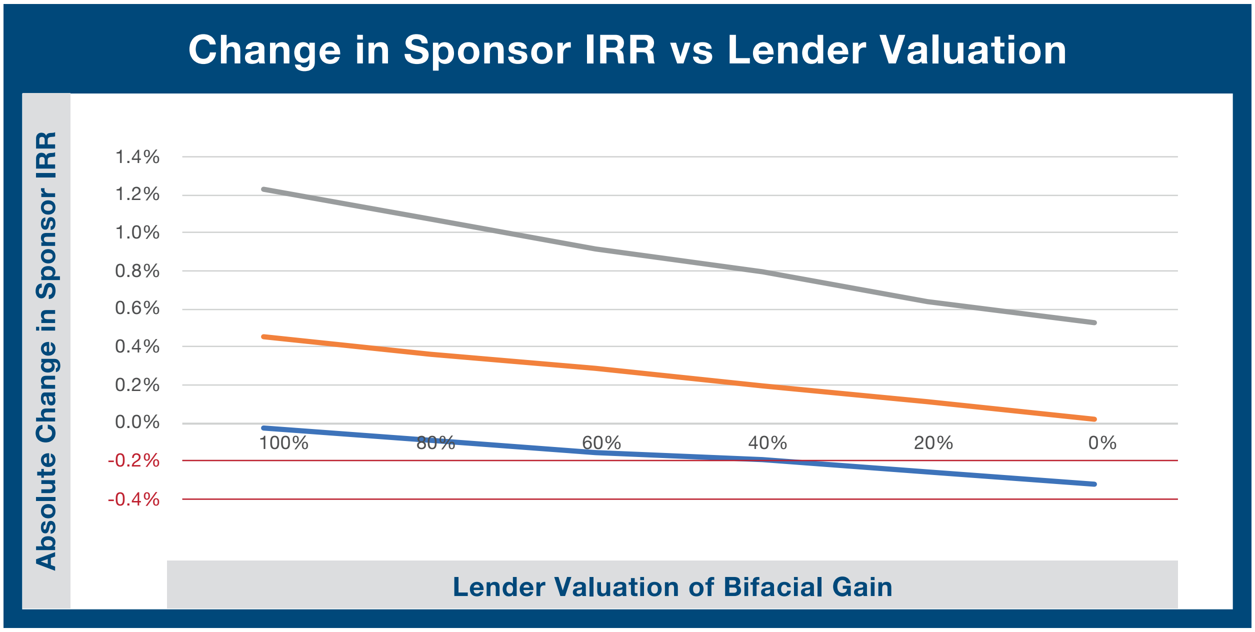
So theoretical projects are great, but what people ultimately want is to know whether to hit "proceed to checkout" on that Amazon Prime bulk order of bifacial modules. What better way to do that than analyze whether it makes sense to incorporate bifacial modules on a real project that is currently in development. Watch the breakdown:

TABLE 2

Low / Mid / High Energy Modeling Inputs			
	Low	Mid	High
Albedo	15%	20%	25%
Structure Shading Factor	25%	20%	6.5%
Rear-Side Mismatch Loss Factor	10%	5%	3%
Bifacial Gain	2.8%	3.8%	5.2%

These energy modeling inputs were chosen to represent the full range of albedos for "grassy" sites, and the rear-side shading and mismatch factors were chosen to represent the widest range of loss assumptions we've seen in the market.

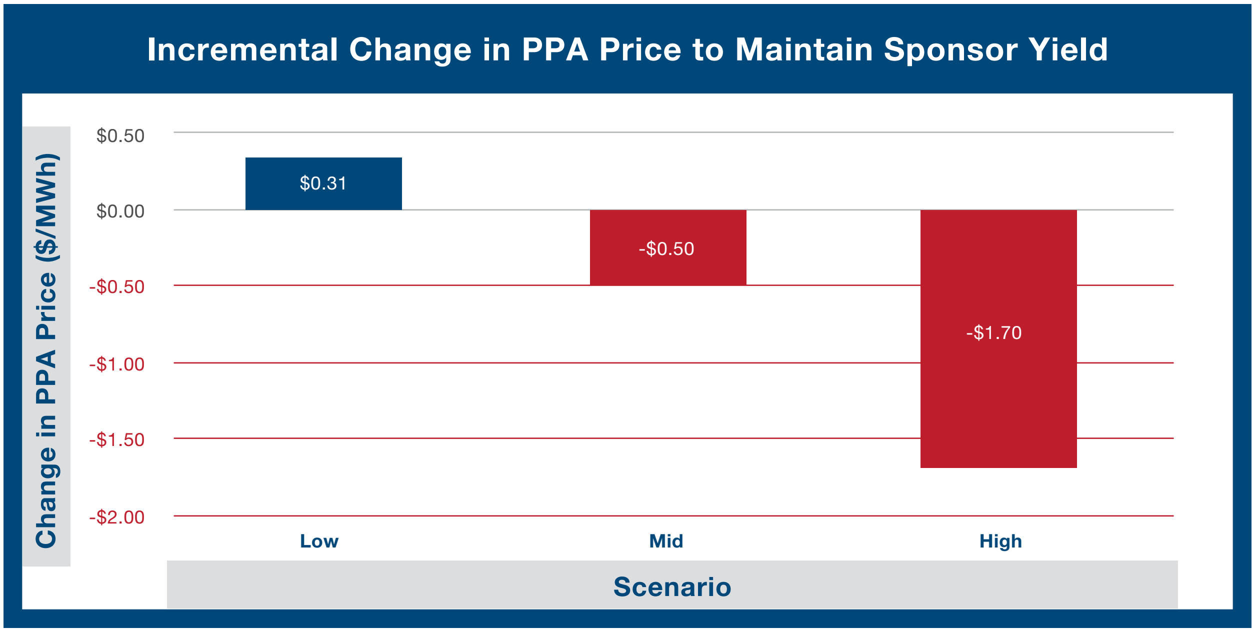
The graph below shows that for this particular project, even when lenders fully value the bifacial gain, the low case (2.8% energy yield increase) does not support the increased costs of going bifacial. However, the mid and high cases begin to present an argument for implementing the technology so long as lenders aren't overly punitive in their valuation of the projected energy yield increase.



As a note on this particular project: this site was not optimized from the beginning with bifacial modules in mind. In fact, as a project in a particularly low-albedo region (~16%), with tight row spacing of a 42% ground coverage ratio, and a high DC:AC ratio of 1.41, this is exactly the type of project and design with which bifacial modules are not supposed to be valuable. Even so, the mid case for energy yield increase leads to a small, but positive, increase in sponsor returns, no matter what valuation is applied to that bifacial gain by the lender. If this project and its design was optimized with bifacial modules in mind from the start, we'd almost certainly see higher returns.

What about PPA prices?

Indeed. Looking at this from the flip side (pun intended), the gain could also translate into a developer's ability to offer a lower PPA price to an offtaker while still maintaining benchmark economics. Using the same low, mid, high methodology, we analyzed the incremental change in PPA price that would support our base case monofacial sponsor return. In the low bifacial gain scenario, the project required a higher PPA price to maintain economics given increased cost and minimal lender valuation of the bifacial gain. In contrast, once we move to the mid and high scenarios, we can reduce the PPA price and still maintain economics. From what we're seeing in the industry, this is already happening, especially on the larger utility-scale side. Bring on the bifacial RFPs.



Wrapping It Up

There's real value to be gained from this technology, but we may have a chicken and egg problem. Recognizing the value of this technology is contingent on multiple parties properly valuing bifacial gain, including lenders. However, lenders may be resistant to doing so until better market data exists, and developers may hesitate to implement the technology until they can calculate tangible benefits through increased sale prices or sponsor returns.

Based on this analysis, even for a site and design that has not been optimized with bifacial modules from the start, a very small increase in energy yield can support the additional equipment and installation costs. While it wasn't necessarily a slam dunk on this particular project, what we take away from this is that bifacial modules should be a part of your evaluation and optimization process for every project.

So get out there and talk to your friendly neighborhood independent engineer. Collect test site data. Work with buyers (like Helios) who know how to assess the value of this technology. There's yield to be had, and the grass may in fact be greener on the other side of the module.

Becca Glazer is a Director on Sol Systems' structured finance team, in which she structures tax-motivated partnership investments for Sol Systems' corporate and institutional clients. Kevin Mayer is a Development Engineering Manager on Sol Systems' customer solutions team focusing on the design, energy modeling, and financing of Sol Systems' projects in development.

Tax equity structuring and the advantage of a tax-efficient sponsor

By Gabe Wuebben

We in the United States, whether in the name of ideological principal or political necessity, have decided to incentivize renewable energy deployment through our tax code. This has produced a byzantine system of rules and regulations surrounding the financing of solar facilities. The result is the proliferation of innumerable complex partnerships with dynamic equity interests, guided by a cabal of accountants and lawyers. In an increasingly competitive marketplace, where margins are shrinking and return hurdles are continually being squeezed, success can hinge on efficiently allocating every last drop of tax benefit across equity members while managing transaction costs.

The principal incentive for deployment of utility-scale solar is the §48 Investment Tax Credit (ITC), which provides for a federal tax credit, equal to approximately 30% of a project's fair market value, to offset federal tax liability on a dollar-for-dollar basis. The first irony of the ITC's design is that most sponsors (those who develop or ultimately own solar assets) do not have enough positive tax liability to set off against the credit. As a result, sponsors seek investors that have tax capacity (the ability to monetize tax benefits like depreciation expense and the ITC), with whom they form tax equity partnerships in order to more efficiently monetize the ITC.

The tax equity investor, typically a bank, insurance company or corporation with significant annual tax liability, contributes equity into the partnership. In exchange, the tax equity investor is allocated the ITC and tax losses (depreciation) to the extent their capital is at risk (as measured via the provisions of IRC 704(b)), as well as an annual minimum cash distribution. The sponsor,

again typically the developer or a later-stage buyer/owner of the asset, collects the majority of cash distributions after debt service. At the conclusion of the ITC compliance period (five years), the tax equity investor will typically exit the partnership, collapsing the multi-investor holding company to a simpler single-member entity.

The vast majority of the tax equity investor community relies upon what is referred to as the Partnership Flip structure to allocate 99% of the ITC to the tax equity investor. There are a number of flavors of the Flip, but most are identified as either time-based or yield-based. In both cases, the tax equity investor is a majority equity holder in the holding company (HoldCo) through a specified period often slightly beyond the ITC's 5-year compliance period, after which its ownership interest flips down to something on the order of 5% and an option permits the sale of the tax equity investor's interest in the HoldCo to sponsor. This structure enables the tax equity investors to absorb the majority (up to 99%) of the tax benefits associated with the project until those tax benefits are exhausted before the majority project ownership flips back to the sponsor.

The allocation of losses during the "pre-flip" period is both complicated and economically impactful for the sponsor and tax equity investor. Both the sponsor and the tax equity investor are limited in the amount of tax losses they are allowed to take under the Internal Revenue Code. Equity partners are allowed to take cash distributions and absorb tax losses only to the extent that they have capital at risk in the partnership. The IRS determines whether a partner has capital at risk based on whether they have a positive or negative 704(b) capital account.

Each partner builds their capital account through either a contribution of capital or property, or through income. Once the tax equity investors have made their investment, every dollar of cash distributed and every dollar of loss (depreciation expense) allocated to them reduces their capital account by a dollar.[1] So in rough terms, assuming a tax equity investor's total contribution to a tax equity partnership represents 40% of the capital stack and the partnership agreement allocates 99% of losses to them (in order to maximize allocation of the ITC), the tax equity investor's capital account would be quickly depleted with more than half of depreciation still remaining to be allocated 99% their way.

A series of mechanisms established by the internal revenue code either prevent a partner's capital account from running negative, or allow for it via a number of remedies. Generally speaking, two schools of thought permeate the market on the reallocation of losses during the "pre-flip" period. Some tax equity investors prefer to reallocate tax losses during the pre-flip period to sponsors, others prefer to utilize the losses and depend upon a Deficit Restoration Obligation (DRO), as detailed below. Both have advantages.

Scenario 1 - Reallocation

The simplest partnership arrangement (typically time-based Partnership Flips) will reallocate losses in excess of the tax equity investor's capital account from the tax equity investor to sponsor once the tax equity investor has depleted their capital account. This is a clean solution, which happens automatically and only needs to be quantified by accountants at the conclusion of each tax year when issuing K1s. Typically, within 1-2 years the tax equity investor reallocates all losses to the sponsor, who then carries those losses forward until they can be utilized against income.

The problem with this solution is that the partners reallocate depreciation, a tax benefit with real-time value, to a sponsor, that more often than not has little to no tax liability and thus no means to monetize the tax benefit. Those losses will simply sit with the sponsor and be carried forward years into the future to offset future project-level taxable income once the depreciation shield is burned off. That's a real drag on the time-value of those benefits and reduces returns either for the sponsor, the tax equity investor, or both

Scenario 2 – Deficit Restoration Obligations

An alternative is a more sophisticated, dynamic flip that employs a Deficit Restoration Obligation (DRO) to permit the tax equity investor's capital account to go negative (though up to a defined amount as specified in the partnership agreement). This structure adheres to the most conservative tax opinion on loss and ITC allocation, as discussed in more detail below. As the DRO permits loss allocation to the tax equity investor in excess of the partner's capital account, no reallocation of losses occurs.

This is a complex mechanism and not all tax equity investors are comfortable taking the risks associated with it. The main risk of allowing the tax equity investor's capital account to go negative is in case of a liquidation event. If the partnership were to liquidate, the tax equity investor would be obligated to contribute

[1] This scenario assumes back-leverage debt. Project-level debt introduces an additional level of complexity that we won't examine here.

additional capital in an amount equal to any capital account deficit, hence the name "deficit restoration obligation". For practical purposes, there is usually sufficient gain upon liquidation to restore capital account deficits. Nonetheless, this arrangement does present a risk to the burdened partner.

Further complicating this arrangement, the tax equity investor's allocation of income and losses is typically optimized via dynamic ownership interests. Starting out at a 99% interest maximizes allocation of tax attributes in Year 1 (the year the ITC is allocated), before dropping to 67% (the maximum permissible reduction in the tax equity investor's equity interest in Year 2) in order to minimize loss allocation in Years 2-5 and thus limit the extent to which the tax equity investor is pushed into a capital account deficit. Finally, once the MACRS depreciation is burned off (the conclusion of Year 5), the tax equity investor's ownership flips back to 99% to allocate the maximum permissible taxable income to the tax equity investor. The positive taxable income digs tax equity investor out of its deficit position until fully restored, at which point an option is executed and tax equity investor exits the partnership. Simple.

This structure checks the box for tax counsel (more below), but like the time-based Partnership Flip, it inefficiently allocates losses to a partner who cannot monetize them. Although the tax equity investor is allocated losses commensurate with its ownership of the partnership (even in excess of capital at risk), those losses cannot be monetized in real time. A number of rules (namely those provided in IRC 704(d)) effectively place those losses on ice via a carryforward-like mechanic. This bag of excess losses is stockpiled until they can be used to offset positive income allocated to tax equity investor (thus the 99% flip back after the majority of depreciation is burned off).

Why? Reallocations jeopardize tax equity investor's perceived true ownership interest in the partnership. The ITC follows, depending upon who you ask, allocations of income OR allocations of income and losses. Moreover, there is no agreement across the industry as to whether that rule applies only to the year in which the ITC is minted (i.e. reallocations in Year 2 and beyond are OK), or whether reallocations at any point during the entire life of the partnership jeopardize the initial allocation of the ITC (bouncing ownership interests, DROs, etc.).

Optimal efficiency – the Inverted Lease + Tax-efficient Sponsor

One way to manage loss allocation to match capital at risk is to structure the partnership via an Inverted Lease (a.k.a Lease Pass Through or Master Lease), which permits the members to deliberately structure the partnerships (yes, there are multiple tiers here) such that the partners' interests in the upper tier partnership (HoldCo or Lessor) are sized to allocate losses to the lower tier partnership (Master Tenant or Lessee).

These losses are sized so that the tax equity investor fully depletes its capital account, with the remaining losses flowing to the sponsor (more below on further optimization). The Lessee entity can then be structured such that the tax equity investor owns 99% of that lower-tier partnership. The ITC is passed through to the MT entity via the master lease, and which can then allocate 99% of the ITC to the tax equity investor, while controlling loss allocation and the extent to which their capital account goes negative. An additional benefit of the Inverted Lease resides in the ability to establish the Fair Market Value of the asset without an asset sale, permitting a ITC benefit comparable to that in a Partnership Flip but without the taxable gain that accompanies the asset sale required in Flips.

Further enhancing this structure, a sponsor who can monetize losses in real time changes the economic proposition as well. Currently, most sponsors (or investors who take equity stakes in sponsors) are pension funds, sovereign funds, or other non-tax-paying entities. Showering losses upon them does nothing to alter their valuations – they focus on pre-tax yield. A sponsor who values tax benefits, however, may be willing to accept a lower pre-tax yield if there are other tax attributes they can monetize. This tax-efficient sponsor, via the Inverted Lease, can even benefit from the 100% expensing made possible via the 2017 Tax Reform, a benefit seldom, if ever, pursued by Flip Investors. As Managing Member of the Helios InfraCo fund, which effectively utilizes this structure to enhance our cost of capital, Sol Systems has seen firsthand how It can positively impact pricing to developers.

Conclusion

Aside from contributing to the advancement of renewable energy, there are strong economic incentives to detangling the complexity inherent in solar finance. Sol Systems currently manages approximately $450M in Tax Equity and Sponsor Equity, across a wide swath of asset classes applying numerous structures and leverage solutions. We've learned that, amongst the myriad components to solar finance, the essential ingredient to successful execution is trustworthy and experienced partners and advisors. Investors all have unique profiles and objectives, so the approach for any new entrant will always have to be tailor-made. At least you've got options.

SOLAR CHATTER

Illinois, building off of the progress being made as a result of 2016's Future Energy Jobs Act, is now pursuing a bill that sets a 100% renewable portfolio standard in its state legislature. SB2132/HB3624, titled Clean Energy Jobs Act (Maryland's 50% bill shares this name), will require the state to be powered by 100% renewable energy by 2050. If passed, Illinois would join California, Hawaii, New Jersey, and New York in 100% clean energy goals, though New York and New Jersey's goals came by way of executive orders.

Following the steep module price drops that we wrote about throughout 2018 due to changing solar policy in China, **in 2019 we're seeing a slight increase of a few percent in module prices over the first quarter of 2019.** The primary cause for this appears to be increased demand from US developers looking to meet the IRS Safe Harbor criteria by procuring 5% of project costs in 2019 to secure the 30% ITC before it begins to step down in 2020.

We're seeing an increase in acquisitions of early-stage development assets in the market. As more competitive capital comes into the market, buying early has arisen as a new differentiator for buyers. Early capital commitment is, in turn, giving developers execution certainty when pricing out much of the project costs.

As battery deployment increases and the associated costs decrease, the question for many developers has continued to focus on which market segments are the most economical for the technology. Currently, state incentives, namely those in Massachusetts and California, are providing the most attractive environment for batteries. Capacity rights, as well as shifting of peak load charges, continue to be key consideration for financiers when pricing out storage-incorporated projects.

Sol Systems CEO Yuri Horwitz Annual Outlook on Solar

This letter was originally posted on Greentech Media

Each year we share our thoughts on the evolution and promise of the solar industry. The last twelve months included tariffs and a president that ignores the fallout of climate change (and reality more generally). Even amid these challenges, the solar industry expanded and matured, as it will in 2019.

As solar technology becomes more efficient, costs continue to fall, rapidly making solar the most cost-competitive source of energy in the country. In direct response to this administration's bewildering approach to climate change and renewable energy, Americans have created and strengthened networks and opportunities to advance renewable energy. State policies have rapidly shifted further in favor of renewable energy, and corporate demand continues to drive procurement.

The solar industry remains a growing multi-billion-dollar market for investors, customers, and entrepreneurs. But it is also a complex one. New investors and developers must be strategic with how they approach the market. Here's one perspective from the front lines that may help along the way.

THE SOLAR INDUSTRY REMAINS POISED FOR GROWTH

America Still Has Our Back...

America overwhelmingly supports renewable energy. As of January 2019, 73% of Americans support the further development of renewable energy (Pew Research Center), which is one of the largest pluralities in history. The United States has the largest electricity load in the world, and these same Americans are electricity customers who support both policy initiatives for renewable energy and who will create the demand for renewables in the next decade. In 2018, we noted that Americans overwhelmingly support our industry, but we did not anticipate how rapidly this would translate into renewable support at the state level.

In 2018, New Jersey passed a Renewable Portfolio Standard (RPS) with a goal of 50% renewables by 2030, and the governor has stated his goal for reaching 100% renewable energy by 2050. The District of Columbia passed a 100% renewable energy goal by 2032. In September 2018, the California State Legislature passed SB100, which requires the state to generate 100% of electricity from carbon-free sources with a 60% renewable portfolio standard built in. New Mexico Gov. Michelle Lujan Grisham **signed an executive order** in January 2019 that commits the state to reduce carbon emissions by at least 45% below 2005 levels by 2030. Governors in Maine, New York, Colorado, and Illinois have all set 100% targets for renewable energy.

These policies have broad and significant impacts on solar regionally, since RPS legislation generally enables both in-state and out-of-state development. Climate change has become one of the most important issues for younger generations, as it should be. These generations are actively changing the prioritization of policy across the political divide. Given the recent Democratic take-overs of six state legislative houses, as well as six governorships, expect additional legislative support for renewables in 2019.

…As Do Corporate Customers

As we anticipated, corporate customers continue to move into direct renewable energy procurement based on corporate sustainability goals and cost savings. In 2018, there were 75 new corporate renewable deals, supporting almost 7GW of new projects. This is twice as much as 2015, the former record year. Expect this trend to continue in 2019, especially in the PJM Interconnection Region where there is tremendous demand from customers, a very large and dynamic market to support solar, pending RPS change, and a federal investment tax credit (ITC) that drives urgency.

How corporate customers acquire solar energy will be the biggest change over the coming year. The corporate customer has evolved from buying voluntary renewable energy certificates (RECs), to buying compliance RECs, to actually contracting for the output of electricity from a specific renewable energy project. This evolution has largely been driven by the concept of additionality. Corporates want to know that there is a causal relationship between their efforts to procure renewable energy and new build.

The primary instrument for customers who wanted to procure electricity from offsite projects in the last three to four years was the contract for difference (CFD). A customer purchases energy from a project at a set price at a set node. The CFD is an elegant solution but it can be baffling for customers. Increasingly, these customers will look to utilities and retail electricity suppliers to sleeve electricity for them and to integrate renewable energy purchases into their bills. NRG and Engie are leading this effort now. Expect new entrants and creative developers to expand this trend in 2019. The suppliers can shape and firm electricity to offer 24/7 electricity to customers. Some corporates, like Google, are doing this on their own.

Costs Continue to Fall & Efficiency Continues to Rise

Costs are driving this rapid change in the industry. All-in costs for solar projects have fallen around 80% since we started our business in 2008. They continue to fall today. A year ago, we projected that the industry would have a low 30 cent module by year-end 2019. At the time, module manufacturers visiting our offices said we were crazy. That was understandable when modules were 50 cents. Modules are now priced at 30 cents (normalized price for power class) and below because the supply of solar modules remains vast, because module production is getting cheaper, and because China has slowed its procurement. We expect this trend to continue.

Additionally, and just as importantly, module efficiency is increasing. Increased adoption of PERC, N-type cells, split cell, and bifacial will drive module performance increasingly upward. A standard 350-watt module in 2018 will become a 380-watt module over the next year, increasing energy density, reducing installation costs, and increasing overall output.

To further this trend, balance of systems (BOS) costs and architecture are improving. Tracker performance at a sub-array level is increasing, (for example, see the TrueCapture technology our friends at Nextracker launched recently) creating a projected 2% more energy. DC optimizers will create 3-5% more energy longer term, while Mono-Perc and Bifacial modules may add up to 5% more efficiency. These are small changes by themselves, but create significant uplift together.

We also see the continued adoption of 1,500V architecture, which enables lower installed cost and higher efficiency at the system level. Additionally, string inverters, previously most common for small commercial applications, will become the predominant solution for small utility projects. String inverters can lower costs, but they also enable a system to partially operate without a "truck roll" and an O&M visit. Bringing down long-term O&M costs is one of the single best ways to create value across an operational portfolio. Expect large solar project portfolios owners like Global Infrastructure Partners, Helios, and Brookfield to focus on these costs to increase returns and financial yields over time. At some point, large portfolio owners will retrofit preexisting systems to include string inverters.

All of this means that we'll build vastly less expensive yet more efficient solar. Utility-scale projects are being built at 90-95 cents/watt right now. That was unthinkable two years ago. We'll build at or below 85 cents/watt in the near future. This pricing has led to sub-3 cent PPA prices from solar projects. There is no other technology that can compete. Lazard, as they have for years, does a great job of illustrating this in their annual Levelized Cost of Energy (LCOE) Report.

Energy storage is the area in which our industry most needs to adapt, as we also noted last year. The question is not if storage will become an integral part of all utility solar projects, but when. Most discussions around storage have been around lithium ion batteries, which are the same batteries in your phone. If you have a Tesla, you're just driving around with 7,000-10,000 phone batteries. This technology holds tremendous promise, but as our friend Colin Murchie explained recently, we'll likely need to integrate pumped water storage and other technologies for true load-shifting. France's use of hydro, where 71% of the electricity is produced by nuclear power plants, is a good template. Companies like Google and asset owners like Brookfield and AVANGRID are already integrating hydro to firm solar and wind. It's a tremendous differentiator, and will continue to be.

The Asset Class Grows

Significant customer demand and falling costs continue to drive the expansion of the solar asset class. In 2018, there were around 109,000MW of solar installed worldwide, with 14,000MW of that capacity installed in the United States. Looking ahead, we still see a tremendous pipeline and significant investor demand. Globally, solar will become one of the dominant sources of new electricity generation, and solar and wind are expected to provide 50% of all electricity in the world by 2050: a roughly $10 trillion market.

Solar assets within the United States are especially attractive for investors because they are dollar-denominated, real assets, non-correlated to the stock market, and are also relatively inflation insulated. Europe and Asia also have specific requirements for banks to invest in renewable energy, as it reduces their capital set-aside requirements. Many sovereign wealth funds and multi-lateral banks have a mandate to invest in renewables. As such, there continues to be a number of new investors in the market from Japan, Europe, the Middle East, and China.

All of these fundamental factors have created a highly competitive and sometimes volatile market. Over the last decade we have repeatedly seen that while the market itself is expanding and solar is becoming a growing share of our electricity, strategic business success is volatile. Generally, expanding markets are complex.

IN COMPLEXITY IS OPPORTUNITY FOR THE INVESTOR

New investor entrants into the U.S. market mean more competition, which drives down the cost of capital for projects. A lower cost of capital generally means that investors are willing to accept lower returns on their investments in solar assets because the investments are viewed as less risky vis a vis alternatives. Because capital costs are relatively high for solar, and ongoing expenses extremely low, a lower cost of capital dramatically drives down the LCOE for solar and PPA prices for the customer. This results in growth for the industry but raises some challenges for certain investors. To compete, these investors must either accept lower returns, take on more operational or structural project risk to maintain their returns, or move earlier in the development cycle to secure pipeline and ensure their targeted returns (which is also a type of risk).

New & More Competitive Investors

This dynamic poses a tremendous opportunity for investors who have a lower cost of capital than the private equity that is currently supporting much of the solar development activity in the United States. These private equity or hedge fund investors find it increasingly difficult to compete in owning solar project assets and thus, are either adapting or looking for new or less mature assets. This trend has occurred in wind a few times.

Many of these private equity investors are being displaced by insurance companies, sovereign wealth funds, and pension funds that buy new or operational assets, or buy down the equity from developers in operational assets or portfolios, in what some refer to as a recycling of capital. In a recent example, AES and its affiliate S-Power transacted with Ullico to sell down equity in their 1,300MW portfolio of renewable assets. John Hancock has been actively buying down equity in portfolios, and a number of developers are actively selling down their equity.

We expect our Helios infrastructure platform to remain competitive and to be a helpful partner for developers in this environment. Also expect NextEra, AVANGRID and EDF to be active participants in this market. Newcomers like Ørsted and Equinor and large Japanese players will also actively participate if they can both adapt to the more complex financial market of the United States and partner with regional firms that understand the investment landscape. Regional or localized partners with development expertise are critical, as they enable these investors to better evaluate projects and risks, navigate a very close-knit community, and aggregate large portfolios.

Investors & IPPs Focus on Development to Boost Returns

This shift in market participation is driving a number of investors and funds that traditionally purchased solar assets when they were complete or beginning construction, to move earlier in the development cycles with an aim to secure pipeline earlier so that they don't have to compete for more mature assets. Another way to look at this is that these investors are trying to preserve yield by investing earlier. While this strategy makes sense in some regards, investors pursuing this strategy need to take care to evaluate the pipelines they buy. Not all projects are created equal.

This evolving investor landscape has similarly impacted independent power producers (IPPs). Many IPPs that traditionally held on to the solar assets they developed are adapting their model from a develop and hold model into a develop and sell model. This is being driven by the opportunity to sell their assets at very competitive prices, and also because most developers/IPPs have a fairly high weighted average cost of capital (WACC) that accounts for the risk imbedded in their development business. This high WACC cannot compete with current institutional capital. This process is accelerated by the fact that many of these same IPPs are also struggling to support early-stage pipeline that is taking longer than anticipated to harvest and are being forced to refinance their capital lines with investors.

Creating Differentiated Financial Products

Other investors seek to gain an advantage through differentiated financial products in the industry. In 2019, a number of investors, including Helios, will finance partially merchant solar projects. Solar projects can either have a merchant tail (and most utility projects do) or a merchant cap, where only a portion of the overall output of the energy is contracted. To enable these projects, certain banks are beginning to offer debt products around primarily or fully merchant solar projects. Already, some banks offer debt products that amortize beyond the PPA term.

We also expect that a number of IPPs and funds will begin to safe harbor solar projects for the 30% ITC by purchasing equipment equal to at least 5% of the eventual cost of the project. This will enable them to utilize the 30% ITC for projects that are operational in 2020 or 2021. We expect NextEra, AVANGRID, and other large developers to invest heavily in this strategy as they have in the past. While it may not seem like much, the difference between a 30% ITC and a 26% ITC will have a marked impact on investor returns and the competitiveness of investors.

NAVIGATING THIS COMPLEXITY AS A DEVELOPER

Development or Contracted Assets? Not All Assets Are Created Equal

In 2018, we warned that assets were overvalued, value conflated, and non-differentiated. Stocks, bonds, and real estate were not trading on market fundamentals. That holds true today, which is why volatility in the stock market has increased rapidly. Investors are looking to reallocate their capital but are challenged to understand where to put their money. As the broader capital markets deleverage, and investors reallocate, they are looking to park their money into stable assets to protect returns. This has been a tailwind for the solar market for the last three years as institutional capital poured into solar assets based on their stability.

In 2019, the costs of capital for solid solar projects with long-term PPAs and contracted revenues will continue to fall. These are tremendous infrastructure assets. The cost of capital for projects now ranges from 6.5-7.75% unlevered after-tax, although 100-300 basis points of that return depends on assumptions and structuring. However, expect the asset differentiation occurring in the broader market to impact what has been a relatively frothy market for solar development assets in the past. Developers with portfolios of projects without a PPA or with no offtake in sight may struggle. This will be a significant issue for the industry over the coming year.

Don't Pack Peanuts

There is a huge difference between a solar project that has contracted revenue and one that does not. It's just one more reason that the customer (and customer demand) will drive our industry. The United States currently has around 150GW (which is insane) of solar in interconnection queues. Many of these projects are have some combination of site control and early stage permits, but don't have a customer offtake, and sometimes they don't even have a strategy for securing a customer. We often refer to these portfolios as a cardboard box with packing peanuts. We urge developers that are considering embarking on this strategy to slow down. It is a capital-intensive strategy in a highly competitive market. We urge investors to carefully value interconnection queues as a basis for pipeline availability. Many of these projects will fail or be warehoused for the future.

One additional hard lesson for the industry (ourselves included) is that many of the new markets are more complex and slower to mature than anticipated. New York, Illinois, Virginia, and much of PJM remains attractive, but project development timelines are being stretched, which means developers must hold these projects either on balance sheets or in relatively expensive development facilities for longer. Pending RPS legislation may make these markets more attractive in the next three years, but the initial timing of many development funds and the high cost of capital in these funds makes it challenging to nourish and develop multi-state portfolios with long lead times. These challenges have put significant pressure on both the developers and the financial partners that provide the capital for many developers to invest in early-stage assets.

As the broader market is deleveraging in 2019, many of the development funds that supported solar development assets from 2015 to 2018 will mature and look to protect returns to investors. These funds will look to capitalize on their investments and will force developers to either partially or fully monetize their assets, and potentially monetize their platforms. As a result, many developers have sold off or will sell off their preexisting pipelines and development assets to source capital and repay these facilities.

Focus on Core Expertise

We recommend that developers pull back from a buckshot approach to markets and focus on a smaller number of states/geographies where they can create differentiated value and a competitive edge. There is a vast chasm between being a successful regional developer and being a successful national developer. That is a journey in which developers can quickly lose capital, focus, and success if they are not careful. Those solar developers that have been disciplined in their approach and focused on the fundamentals in their markets (locational marginal pricing, congestion, and policy) have succeeded and will continue to do so.

OPPORTUNITY AMID CHANGE

The long-term fundamentals are there for our industry to succeed, and we expect solar to continue to grow into the single largest source of electricity in the United States. There are two fundamental calibrations that are occurring in the industry right now that are important to recognize.

First, there are a large number of investors looking to enter the market or gain market share. These investors are outcompeting traditional investors, who are in turn looking to secure yield by creating differentiated value through more creative financial structuring or by buying earlier stage assets.

Second, many developers have cast a wide net in the market and will be challenged to financially support these vast pipelines. The developers will either sell or refinance their portfolios, or in some cases will sell their development platform. Others will refocus their attention on a more regionalized geographic approach.

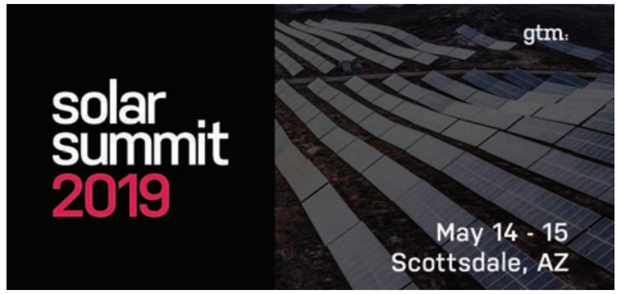
Of course, these trends naturally merge in some ways, and the investors and developers that can navigate the opportunity will create enormous value. We urge investors to dig deeply with partners to understand imbedded project risks. We urge developers to stay focused on core markets and to work to understand the fundamentals of the increasingly larger and more complex electricity market that will drive real-time locational pricing and customer demand for the coming decades.

The Sol Systems team is excited to play our part in helping this industry expand and succeed to confront the generational challenges of climate change and energy infrastructure transformation. We wouldn't want to be doing anything else, with anyone else. Good luck to all of you who commit your lives to this industry.

It is not easy; it is important.

UPCOMING EVENTS

California Solar Power Expo
April 25-26, San Diego, CA



GTM Solar Summit 2019
May 14-15, Scottsdale, AZ

Novogradac 2019 Financing Renewable Energy Tax Credits Conference
May 23-24, San Francisco, CA

CONTACT US

If you have any questions about this information, wish to receive our quarterly newsletter via email, please contact our team. We would love to hear from you.

888.235.1538 or **SOURCE@solsystems.com**