Hawaii Tackles How To Handle *Too Much Solar*

Some insight on how grid operators are confronting curtailment.

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THE INNOVATIVE LEAK-PROOF, MICROFLASHED QUICKBOLT FOR ASPHALT SHINGLE ROOFS

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Joseph Bebon

As I might’ve mentioned before, I genuinely enjoy going to solar sector trade shows: Where else do you get to meet so many industry insiders, learn about new and upcoming technology, collect a few cool knickknacks, and, of course, get to network while (responsibly) sipping on one or two complimentary drinks? What I definitely haven’t mentioned, though, is that I am terrified of flying.

Statistically, I know there’s a better chance of getting struck by lightning or run over by a cow or something than being in an airplane accident, but for whatever irrational reason, planes still frighten me. That’s why I was so excited to go to a recent conference in nearby Boston. Driving, though statistically more dangerous than flying, is fine by me, especially when the weather is clear and the music good.

As I neared the end of my drive from Connecticut to Boston, I saw a massive rooftop solar array on one side of me and a wind turbine on the other. The awesome sight made me smile - clearly, Massachusetts understands the value of renewable energy, and I could tell this was going to be a good trade show. Ultimately, the omen proved true, and on my way home from the conference, I saw yet another large solar array, this time ground-mounted, located adjacent to a rest stop on the highway. A sign indicated the project was part of a Massachusetts state program.

The Bay State has been actively pursuing clean energy leadership for years, and obviously, the effort is paying off. According to the Solar Energy Industries Association (SEIA), Massachusetts is home to around 15,000 solar jobs and ranks among the top 10 solar states in the country, with about 1.5 GW of cumulative installed capacity as of the end of 2016. More recently, I’ve also noticed an uptick in solar announcements coming out of the state, most notably community solar projects.

Massachusetts’ renewable energy success is due, in large part, to support from state officials, lawmakers and regulators. For example, Gov. Charlie Baker has been a vocal solar and energy storage advocate. Although some may claim renewable energy is traditionally a “Democrat thing,” as a Republican, Baker demonstrated that clean energy isn’t a partisan issue – a finding numerous U.S. polls discovered during the 2016 elections. Last April, Baker signed bipartisan legislation to raise the state’s net-metering cap, and he declared solar development “will be an integral component of our state’s clean energy future.” The governor’s predecessor, Deval Patrick, was also a major solar supporter who helped the state meet a solar capacity target four years early.

Established by the state legislature, Massachusetts’ renewable portfolio standard has been a big catalyst of clean energy development, as well, and some state lawmakers have even introduced an ambitious bill to increase the mandate to 100% renewables. Then, of course, there’s the state’s Solar Renewable Energy Credit (SREC) program, which had a few issues early on but has been wildly successful overall. Solar groups recently praised the state Department of Energy Resources (DOER) for extending the SREC II program further into 2017 as the agency ironed out details for a long-term replacement of the program.

Sean Gallagher, vice president of state affairs at SEIA, called the extension “a much-needed bridge between the end of the current solar incentive program and the beginning of the new one.” He added, “This action will allow new solar projects to move forward, creating jobs, valuable investment dollars and a well-deserved reputation for Massachusetts as one of America’s top solar states.” According to a DOER document, the proposed replacement plan is the result of a multi-stakeholder process and would aim to add another 1.6 GW of solar through a so-called “declining block” program.

For the most part, Massachusetts has done what’s necessary to proliferate renewables, and policymakers in many other states across the U.S. would do well to follow down the same road.
Be the most versatile player on the worksite with the new Self-Contained Track Rig (STR-20). One machine with the flexibility of three tools right at your fingertips makes you the MVP of any worksite.
Brookfield To Take Over SunEdison’s TerraForm Yieldcos

It appears TerraForm Global and TerraForm Power, yieldcos of bankrupt renewables firm SunEdison, will finally be able to come out from underneath the shadow of their troubled parent company. Canada-based Brookfield Asset Management has agreed to fully acquire TerraForm Global, as well as acquire a controlling stake and assume sponsorship of TerraForm Power.

Although neither yieldco was part of SunEdison’s Chapter 11 bankruptcy filing in April 2016, SunEdison’s financial woes weighed heavily on the subsidiaries’ operations. Under the yieldco model, SunEdison, as the sponsor, would sell its operating projects to the TerraForm companies - a relationship that provided the yieldcos with a steady project pipeline to own and operate and SunEdison with more capital for future projects.

After SunEdison’s bankruptcy, however, the yieldcos started searching for buyers or new sponsors in an effort to break away from their parent and remain viable companies. They recently signed exclusivity agreements with Brookfield regarding a possible buyout, and now they have inked definitive deals.

According to a press release, TerraForm Global owns and operates, or has contracts to acquire, a fleet of 31 wind and solar power plants totaling 952 MW of capacity spread across Brazil, India, China, South Africa, Thailand, Malaysia and Uruguay. Under a definitive merger agreement, Brookfield Asset Management Inc., a global alternative asset manager, will acquire TerraForm Global for approximately $787 million in cash and will assume approximately $455 million in net debt, representing an enterprise value of approximately $1.3 billion.

“We are pleased to have reached a successful completion of TerraForm Global’s strategic alternatives process to maximize value for our shareholders,” says Peter Blackmore, chairman and interim CEO of the TerraForm yieldcos. “After a thorough review of alternatives and the significant steps taken by the board and management to best position TerraForm Global for success, we are confident a sale to Brookfield is the best possible transaction for our shareholders. We look forward to working closely with Brookfield’s experienced team to achieve a timely closing and a seamless transition.”

In addition, Brookfield has entered into a definitive agreement with TerraForm Power under which Brookfield will acquire 51%, a controlling interest, of TerraForm Power and assume the role of the yieldco’s sponsor.

According to a press release, TerraForm Power Class A shareholders will receive $11.46 per share in cash, with an option for shareholders to elect shares in order to participate in future upside potential. Brookfield will provide TerraForm Power with a 3.5 GW right-of-first-offer portfolio, representing about 1.2 GW of operating wind projects and around 2.3 GW of development-stage wind and solar projects in North America and western Europe. Brookfield will also offer a $500 million sponsor equity line to support future growth for TerraForm Power.

Blackmore says, “This agreement with Brookfield is the culmination of our efforts to separate our operations from SunEdison and to position TerraForm Power for future success. With the support of Brookfield as TerraForm Power’s sponsor, we will gain additional resources to continue to expand our portfolio and increase cashflow on a per-share basis. We look forward to working with the talented Brookfield team to achieve a smooth transition.”

Sachin Shah, senior managing partner of Brookfield, comments, “We are confident that our significant renewable power...
operating experience, financial resources and global institutional relationships will provide TerraForm Power with strong financial flexibility and an attractive pipeline for growth moving forward. We look forward to participating alongside all shareholders in capturing future upside and helping the business to achieve its full potential over time.”

Brookfield’s transactions with the two yieldcos, though separate, are both expected to be completed in the second half of this year, so long as they meet various closing conditions, including approval of the U.S. bankruptcy court overseeing the SunEdison Chapter 11 case.

John Dubel, SunEdison’s CEO and chief restructuring officer, says SunEdison supports both transactions. In fact, SunEdison has reached settlement agreements with TerraForm Global and TerraForm Power that contain certain terms to resolve the complex legal relationship between the yieldcos and SunEdison. That deal also requires court approval.

For its part, SunEdison has been working to emerge from bankruptcy, namely by selling off large portfolios of its project assets over the past year or so.

The company’s rapid rise and fall created fallout in the U.S. solar market in 2016, reducing investor appetite and bringing into question the viability of the yieldco model. However, Raj Prabhu, CEO and co-founder of clean energy communications and research firm Mercom Capital Group, says these new TerraForm agreements “certainly provide closure to a bad chapter in the solar industry and get SunEdison’s name out of these assets. That said, the investment community and other renewable-energy-focused yieldcos have already put this behind them. Most other yieldcos are in positive territory (in terms of stock price).”

Amazon Launches Global Rooftop Solar Initiative

The next time we order a last-minute birthday or holiday gift online, it might be shipped from a solar-powered warehouse!

E-retail giant Amazon has launched a new initiative to install solar panels on its fulfillment facilities around the world. The company initially plans to deploy large-scale solar systems on rooftops of more than 15 fulfillment and sortation centers in the U.S. this year and is planning to deploy solar systems on 50 fulfillment and sortation centers globally by 2020.

“As our fulfillment network continues to expand, we want to help generate more renewable energy at both existing and new facilities around the world in partnership with community and business leaders,” explains Dave Clark, Amazon’s senior...
vice president of worldwide operations. “By diversifying our energy portfolio, we can keep business costs low and pass along further savings to customers. It’s a win-win.”

According to the company, the initial solar projects planned for completion by the end of 2017 will generate up to 41 MW of power at Amazon facilities in California, New Jersey, Maryland, Nevada and Delaware. Depending on the specific project, time of year and other factors, a solar installation could generate as much as 80% of a single fulfillment facility’s annual energy needs. For example, Amazon says solar panels installed on the rooftop of the Patterson, Calif., fulfillment center cover more than three-quarters of the 1.1 million square-foot building’s rooftop and will capture California’s most generous resource to power the hundreds of Amazon Robotics utilized by associates at ground-level.

Amazon notes its recent renewable energy projects include the company’s largest wind farm to date, located in Texas. In addition, a network of wind and solar farms in Indiana, North Carolina, Ohio and Virginia are delivering energy onto the electric grid that powers AWS data centers. According to the 2017 State of Green Business report, the company was the leading corporate purchaser of renewable energy in the U.S. in 2016.

Additionally, Amazon has expanded its Career Choice program to include funding for associates to earn North American Board of Certified Energy Practitioners (NABCEP) certification. To qualify for the exam and become a certified solar PV installer for commercial and residential projects, associates in this program will participate in 40 to 80 hours of PV design principles and practices learning, OSHA training, and hands-on installations, all of which can be provided by local community colleges and other participating accredited educational organizations. Because the solar industry is growing so quickly, Amazon says many PV installers may quickly find themselves in leadership roles as managers, designers, and developers of renewable energy projects across the globe.

“The NABCEP professional accreditation is a springboard for fulfillment center associates to enter a rapidly growing and in-demand workforce outside of Amazon as PV installers,” states Kara Hurst, director of Amazon’s worldwide sustainability. “It would be great one day soon to see former associates developing solar systems on the rooftops of our fulfillment centers.”

Florida Utility FPL Doubles Down On Solar Plans

Florida Power & Light Co. (FPL) has announced it is effectively doubling its near-term commitment to build new utility-scale solar projects across the Sunshine State.

FPL recently revealed plans to install four new large-scale solar projects this year, but the company says it is now expanding that commitment to total eight new projects across Florida by early 2018. According to FPL, the eight solar plants will collectively feature more than 2.5 million new solar panels - enough to wrap around Florida’s coastline more than two times.

Each of the eight new solar plants will be 74.5 MW in capacity for a total of nearly 600 MW. Construction is slated to commence this spring, and at the height of construction, FPL expects each of the sites to employ about 200 people for a total of approximately 1,600 jobs.

“With the support of communities across the state, we are advancing smart, affordable clean energy infrastructure while keeping customer bills low,” says FPL President and CEO Eric Silagy. “On a per-megawatt basis, these eight new plants will be the lowest-cost solar ever built in Florida and some of the lowest-cost solar ever built in America. Our steadfast commitment to delivering solar cost-effectively directly benefits our customers, our environment and the economy.”

FPL says it currently operates more than 335 MW of solar generating capacity, enough to power 60,000 homes. Despite the utility’s apparent support of utility-scale solar, however, FPL and other Florida utilities came under fire last year for reportedly backing a controversial ballot measure aimed at small-scale solar in the state. Florida voters ultimately rejected the measure, known as Amendment 1, in the November general election.

What’s Ahead For The U.S. Solar Market?

Following a record-breaking 2016, total installed U.S. solar capacity is poised to nearly triple over the next five years, according to the U.S. Solar Market Insight 2016 Year-in-Review report. However, that includes a 10% slump in 2017.

After providing an encouraging preview of the report in February, the Solar Energy Industries Association (SEIA) has officially launched the new study in partnership with GTM Research. The report offers even more stats behind the U.S. industry’s historic year, as well as provides new forecasts for what lies ahead.

As SEIA previously revealed, the U.S. solar market had its biggest year yet in 2016, nearly doubling its previous installation record and adding more electric generating capacity than any other source of U.S. energy for the first time ever. Notably, though, the newest data says the U.S. added 14.8 GW of installed capacity in 2016, up from the previous tally of about 14.6 GW.

Adding to those findings, the report offers a stunning statistic - one new megawatt of solar PV capacity went online in the U.S. every 36 minutes last year. The report adds that 22 states each installed more than 100 MW in 2016, up from just two states in 2010. The report notes there was high growth in states that are not known for their solar market, including Georgia, Minnesota, South Carolina and Utah.

On average, the report continues, U.S. solar PV system pricing fell by nearly 20% in 2016. This is the greatest average year-over-year price decline since GTM Research began modeling pricing in this report series.

“It would be hard to overstate how impressive 2016 was for the solar industry,” said Abigail Ross Hopper, SEIA’s president and CEO. “Prices dropped to all-time lows,
installations expanded in states across the country and job numbers soared."

Looking ahead, the report forecasts that an impressive 13.2 GW of solar PV will be installed in the U.S. in 2017. Although that is a 10% drop from 2016, the figure still represents 75% more than what was installed in 2015, the previous record year.

According to the report, the dip will occur solely in the utility-scale market, following the unprecedented number of utility-scale projects that came online in the latter half of 2016, most originally scheduled for completion before the original expiration of the federal investment tax credit, which has since been extended. By 2019, the utility-scale segment is expected to rebound, with year-over-year growth across the board.

At 19%, U.S. residential PV saw its growth slow in 2016 from record growth in 2015 - which the report says was due to second-half slowdowns in a handful of established state markets, offset somewhat by the emergence of several new state markets. The report says the residential segment is slated to grow 9% in 2017. California, which has historically accounted for nearly half of the U.S. residential market, is expected to decline in 2017; however, 36 of the 40 tracked states will grow year-over-year, the report notes.

“Though utility PV will reset from an origination perspective starting in 2017-2018, distributed solar is largely expected to continue to grow over the next few years due to rapid system cost declines and a growing number of states reaching grid parity,” says Corey Honeyman, associate director of GTM Research. “That said, ongoing NEM and rate design battles - in conjunction with a declining incentive environment for non-residential PV - will continue to present risks to distributed solar growth.”

The non-residential market is expected to grow 11% year-over-year and install a record 1,756 MW in 2017. The report says the community solar market, which nearly quadrupled from 2015 to 2016 due to major installations in Minnesota and Massachusetts, is anticipated to represent 30% of the non-residential market in 2018.

By 2019, the report says, the U.S. solar market is expected to resume year-over-year growth across all market segments, and by 2022, more than 18 GW of solar PV capacity will be installed annually, with 24 states being home to more than 1 GW of operating solar PV, up from nine today.

According to the report, total installed U.S. solar capacity, including mostly PV and some concentrating solar power, is expected to grow from about 42.4 GW in 2016 to around 111.1 GW by the end of 2021.

“The bottom line is that more people are benefiting from solar now than at any point in the past, and while the market is changing, the broader trend over the next five years is going in one direction - and that’s up,” concludes Hopper. 
Grupo Clavijo And MFV Solar Announce PV Tracker Merger

The Spanish companies Grupo Clavijo and MFV Solar, with the support of the Q-Growth Fund, have reached a merger agreement to form NCLAVE. The combined entity will aim to become a world leader in the design, manufacture and installation of structures and trackers for the solar photovoltaic market.

NCLAVE now has more than 10 years of experience, during which it has installed over 2 GW in 40 countries; and it is scheduled to install 600 MW in the coming months. It currently has offices and production centers on five continents, making it a global company.

Grupo Clavijo, with its headquarters in Viana, Spain, has been active in Latin America, the U.S., and the MENA region and has production plants and offices in Chile, the U.S., Brazil and Australia. In turn, MFV Solar, with its headquarters in Valencia, Spain, has a long track record, with installations in various countries in Europe, Latin America and Asia.

“The merger with MFV Solar is a strategic step that strengthens our companies’ international standing in the structures and solar trackers sector. Furthermore, with the support of Q-Growth, we are taking a major step toward making the most advanced solar tracking technology available to developers, EPC contractors and installers worldwide,” says Miguel Clavijo, CEO of Grupo Clavijo.

Ron Corio, CEO of New Mexico-based solar tracker manufacturer Array Technologies Inc., has also chimed in on what this new merger signifies.

“Solar tracking technologies have quickly moved from a ‘nice to have’ feature to a core technology that drives the overall success of a utility-scale PV installation,” says Corio. “The merger between Grupo Clavijo and MFV Solar is a classic effect of market maturation - consolidation within the industry. With 28 years of strong growth in the industry under our belt, Array Technologies is pleased to see more and more signs of the increasing global demand for solar trackers.”

Meyer Burger To Discontinue Diamond Wire Production In Colo.

Meyer Burger Technology Ltd., a Switzerland-based PV manufacturing equipment provider, has announced it is discontinuing its diamond wire production at Diamond Materials Tech Inc. (DMT) in Colorado Springs, Colo. - a decision that will lead to a workforce reduction of 72 employees.

Preliminary 2016 financial results show Meyer Burger’s net sales increased by 40% compared with the previous year, and EBITDA was positive at about $10 million, compared with a negative EBITDA of about $55 million in 2015. Nonetheless, Meyer Burger says DMT, a member company, has been facing continuing global pressure on prices and margins for diamond wire volume production for quite some time. The company has executed several cost optimizations, capacity adjustments and restructuring measures since 2012. Meyer Burger says despite this and due to the fact that diamond wire production in the solar industry has become a commodity business over the cycle, DMT has not been able to develop the diamond wire production into a profitable business unit.

“The decision to discontinue this business activity of DMT has not been an easy one. But it is an important and necessary step on our path to quickly and sustainably improve profitability of the entire Meyer Burger Group and thereby secure the successful and long-term future of the company,” says Hans Brändle, CEO of Meyer Burger.

Meyer Burger says this decision does not influence its product line of diamond-wire-based cutting equipment, such as the DW 288, which is used for the production of silicon and sapphire wafers. Customers will be able to obtain suitable diamond wire for the DW 288 Series 3 and future developments of the diamond wire cutting technologies from third parties, the company adds. As a result of the strategic decision concerning DMT, Meyer Burger says it can reduce its annualized operating cost base by about $10 million as of the second half of 2017 and will lead to one-time, non-cash-related depreciation and impairment of inventory, technology and manufacturing equipment in an amount of about $12 million.
Tigo Introduces PV Optimizers With UHD-Core Tech

Tigo has announced the worldwide release of its next generation of solar optimizers, now featuring UHD-Core (Ultra-High Definition) technology. The UHD-Core technology is available within Tigo’s TS4 products: TS4-O (Optimization) and TS4-L (Long Strings) optimizers. With a new design architecture and component rating, Tigo’s TS4-O and TS4-L support up to 90 V maximum input voltage and 12 A maximum input current. The company says the UHD-Core results in higher energy harvest, with optimization efficiency up to 99.6% for any module up to 475 W.

“This first-in-class UHD-Core technology is now the solar industry’s highest-powered single module optimizer solution,” claims Zvi Alon, CEO of Tigo. “This innovation can lower the cost of the optimizers by 30 percent while improving the power range, increasing the efficiency and extending the vendor’s inventory of the modules it supports.”

The new optimizers with UHD-Core technology join Tigo’s existing TS4 platform members. They are fully monitored through Tigo’s Cloud Connect Advanced data loggers, with remotely upgradeable firmware. The new TS4-O and TS4-L further employ monitoring capability to also provide remote access to individual module information - such as panel type, barcode, manufacturing origin, location and production date. Furthermore, these products now comply with NEC 2014 & 2017 Rapid Shutdown requirements, with a recently awarded UL certification.

Tigo says all of its TS4 platform products are autonomous and feature selective deployment. They can be fitted to new or existing installations on any string or sub-string size, driving the optimization cost as low as $0.02/W, according to the company. Selective deployment is compatible with most of Tigo’s inverter partners and any module type, including monocrystalline, polycrystalline, thin-film and bifacial.

Tigo’s TS4-O and TS4-L with UHD-Core technology for modules up to 475 W are shipping immediately. TS4-O and TS4-L are available as integrated and retrofit/add-on solutions.

DuPont Unveils Metallization Pastes For Screen Printing

DuPont Photovoltaic Solutions has introduced new innovations for its DuPont Solamet photovoltaic metallization paste to enable advanced screen printing.

Specially designed for double printing, Solamet PVD1x and PVD2x comprise an integrated two-layer solution with compatibility that helps maximize cell performance. The first layer demonstrates super low contact resistance and excellent fine line printing, while the second layer delivers better electrical conductance and good solderability for high adhesion, according to the company, which says the solution for double printing enables more than 0.1% efficiency gain.

DuPont has also introduced Solamet PVM1x to support the new development of the Mesh-Cross-Free (MCF) screen. The company says Solamet PVM1x has excellent matchability with various MCF parameters, outstanding printability, and yield to both multi and mono wafers, with 0.1% efficiency gain.

DuPont unveiled the new products at a recent expo in Japan, where the company collaborated with Taiwan Solar Energy Co. (TSEC) to demonstrate the increased efficiency and power output that DuPont Solamet technology can provide. DuPont says TSEC, which specializes in manufacturing mono- and polycrystalline silicon solar cells and modules, has observed 21.15% cell efficiency and module power output as high as 305 W (60 pcs) in its mono PERC modules.

Storage Company sonnen Establishes U.S. Hub In Atlanta

sonnen, a Germany-based residential energy storage company, says it is increasing its investment in the growing U.S. market by establishing a new InnovationHub to combine the firm’s U.S. manufacturing operations and product research and development (R&D) under one roof. Located in Atlanta, the new facility is expected to begin production of sonnenBattery products in the second quarter of this year.

“Sonnen U.S. has experienced exponential sales growth over the past year, making the sonnen InnovationHub a smart investment to capitalize upon the immense potential of the North American energy storage market,” says Christoph Ostermann, sonnen Group CEO.

Sonnen says it has already begun renovations to the existing facility in Atlanta, and the new InnovationHub will bring additional cleantech jobs to the Southeast and a sonnen presence to the East Coast, complementing the company’s office in Los Angeles.

“It’s gratifying and exciting for us when an innovative technology company like sonnen expands their footprint in Georgia,” comments Costas Simoglou, director of the Georgia Department of Economic Development’s Center of Innovation for Energy Technology. “The sonnen InnovationHub is another success story that puts solar energy storage, a very critical part of the solar energy ecosystem, in the spotlight.”

Sonnen says it has deployed over 16,000 battery storage systems globally. “The U.S. market represents significant opportunity for sonnen as we look to expand and encourage energy independence globally,” states Blake Richetta, vice president of sales for sonnen North America. “We’re seeing a rapidly growing number of homeowners interested in achieving energy independence, and a large portion of those are seeking smart storage and software capabilities for better efficiency and management of their renewable energy output.”
Navigating A Solar Market Long On Dollars But Short On Projects

The U.S. solar industry has entered an increasingly mature phase, where falling equipment costs and rising consumer demand open new markets and attract a stable base of investors with a firm understanding of the large and medium solar asset classes. But this rising demand and funding interest are creating a new challenge for utility-scale and commercial and industrial (C&I) solar developers - a market long on investment dollars but short on investment-ready projects.

A confluence of events has generated the current solar market situation. Interest rates remain low, meaning investors with good credit can raise large amounts of capital. Utility-scale and C&I solar projects have evidenced steady yields for many years, making them attractive to investors seeking consistent rates of return. Utilities and energy funds are looking to expand their solar capacity, adding competition for project acquisition. Finally, new tax equity investors are increasingly comfortable with the solar investment tax credit (ITC) subsequent to its extension and want to enter the market.

However, the move to available markets and the rush to beat the ITC cliff picked off most of the low-hanging development fruit, leaving scarce options for the funds flowing into the non-residential solar markets. There’s never been a perfect balance between investment opportunities and investment funding, but right now as a market, we’re seeing more dollars than investment opportunities. The challenge currently facing the U.S. utility-scale and C&I solar industry, therefore, is how to build a valuable pipeline and create or acquire projects.

Open up the fundamental developer toolbox

Given all this, how can developers capitalize on solar’s more mature market dynamics? Although the variables have changed, the same scalable business formula that has always underpinned solar success remains constant: understanding local markets and pursuing the development process with the right partners.

This starts with what we call the “fundamental developer toolbox” - the skills, knowledge, and pattern recognition needed to take a project from concept to notice to proceed. At the local level, this includes understanding land entitlement, a knowledge of interconnection and how to get power to the market, and being able to put the right contracts in place to sell power and renewable energy credits to generate revenue streams.

We’ve seen plenty examples of what happens when fundamental development skills aren’t employed. For instance, developers agree to project power purchase agreements (PPAs) at rates that are attractive to the customers but are too low to produce adequate revenues needed for financing, leading to difficulty in getting the projects financed or sold.

In this instance, utility-scale and C&I developers should leverage historic low solar component prices with off-takers that might be willing to consider traditional energy market volatility and strike a PPA that’s slightly above market value with an escalator. This way, developers and customers can catch the low part of the market and hedge out pricing volatility in order to move forward in a way that generates energy cost savings and consistent profits for asset owners.

We’ve also seen developers pursue plenty of projects in states with favorable solar incentives or targets that seem promising from afar but face local market challenges - such as being located at nodes where the value of electricity is too low to make a profit, or in areas without enough existing infrastructure to provide interconnection points.

For example, solar development has been successfully concentrated in some parts of southern New York, where higher tariffs are offered to projects, but it is challenging in other regions that maintain lower tariffs under the current state program design. In New Jersey, interconnection is difficult in southern utility service territories despite favorable state incentives. Even in Virginia, where favorable project development opportunities are linked to the liquid PJM markets, power prices in some regions of the state are extremely low.

Here’s some advice on how developers can find continued success in the maturing U.S. market.

by Jesse Grossman
Navigating A Solar Market Long
On Dollars But Short On Projects

The 5.6 MW Morin solar facility in Warren, Mass. Photo courtesy of Soltage
In selecting and addressing development opportunities like these across the U.S., functional partnerships between developers and investors are often key to success. These partnerships help drive both the developer and investor through the decision-making processes, from site selection and entitlement, to engineering and interconnection, and right through permitting and accurate PPA pricing. If a partnership like this is locked in early on, projects will be developed with an investment exit in mind, de-risking the all-important question of who will ultimately take over the project ownership once it has been successfully developed.

Understanding the solar investment thesis

Beyond fundamental development skills, building a replicable business strategy requires adapting to market-proven investment standards by understanding the current and evolving solar investment thesis. This includes awareness of the risks and rewards project owners are looking to sign onto, if they are willing to assume long-term ownership through asset investments, and how developers can ensure projects have sufficient funds to take asset development through construction into term ownership.

The solar investment thesis is slightly different in each market, but it ultimately comes down to whether or not projects clear the economic hurdles to ownership. The return side of this equation is cut and dry: Do the benefits of the project’s long-term value offset the risks and costs associated with its development?

The risk side of the investment thesis is specific to each project: What are the regulatory regimes each project will interact with? What off-taker contracts and lengths will make financial sense? Will projects be developed for a single credit-rated utility, or will they be community solar developments with 150 to 200 entities per megawatt on the other side of the contract?

Evolving interest rates also complicate the solar investment thesis and investment universe dynamic. General industry consensus is that interest rates have nowhere to go but up, and this will likely translate to a universe in which projects with lower investment rates of return and lower PPAs will face a more challenging funding environment.

Here, developers will have to be careful about how they’re pricing PPAs so that they are anticipating the equity returns needed when they’re ready to build projects six or nine months into the development process, even if debt goes up 50 or 100 basis points.

Utilities in non-traditional solar markets: a promising new vertical

Using fundamental solar development skills alongside an understanding of emerging solar investors and owners reveals promising opportunities to turn development work and investment dollars into projects through emerging solar industry verticals.

Just as declining costs and steady returns have broadened the opportunity for solar development and investment across the U.S., the market has seen the emergence of investor-owned utilities and independent power producers buying into non-traditional renewable energy markets as they seek greater exposure to solar generation and associated investment opportunities.

This trend has been most prominent in the southeast U.S., where utilities are effectively creating their own markets by announcing significant new solar capacity targets within their service territories. For instance, Georgia Power is targeting 1.6 GW of new renewables capacity, Duke Energy has an 8 GW renewables by 2020 goal, and Alabama Power has been approved to add 500 MW of renewables, including large-scale solar.

Utility solar demand is also being driven by PURPA requirements, which GTM Research forecasts will supplant renewable portfolio standards to spur a majority of new solar capacity installations starting in 2017. This trend has been on display across solar-leading states like North Carolina and is projected to be increasingly evident in non-traditional markets like Montana, Oregon, Nevada and South Carolina.

Across these markets with large energy participants, developers are traditionally employing one of two models. With development for third-party ownership, the focus is on establishing interconnection and striking PPAs with the utilities at rates that will support efficient financing of the solar asset.
as well as the creation of a long-term valuable investment or ownership opportunity.

In other cases, utilities can be interested themselves in buying projects developed in their service territory. In this scenario, the developer will be developing and contracting the solar asset with a view to ultimately selling the solar project in whole or in part to the utility. Either of these strategies creates a credible pathway for solar developers to build portfolios in these service territories, with the goal of selling power or projects to utilities seeking to grow their solar capacity.

Dig deeper on corporate renewables for new opportunity

The developer toolbox and investment thesis also open up solar investment opportunities in the medium- to small-corporate client market, even if they’re a bit more difficult to finance and develop. Large corporate renewable clients are no secret, but developers are targeting all of the same opportunities, and that market has become a crowded space.

Looking outside the Fortune 50 or Fortune 100 list reveals numerous good-credit entities in the U.S. that aren’t on the radar of every development shop. Although these smaller corporate clients may not represent massive portfolio potential, they’re an untapped market, and the investment thesis holds true regardless of whether they’re seeking behind-the-meter or off-site generation options. As with any buyer of power, corporate clients seek credible developers, and companies should play up their deployment track record while they put a specific cost-savings solution on the table.

The small- to medium-commercial solar space has been called a “no man’s land” for developers because developers often either don’t have the bandwidth to approach smaller businesses or they don’t have the ability to invest in such projects. This has certainly been a difficult part of the market to scale up, with consistently less capacity added than residential and utility-sale solar since 2014.

However, companies can capitalize on small and medium corporate solar opportunities by using a finance-first approach under which developers set up a financial vehicle able to manage numerous smaller investments. Provided that firms build out the ground game or local partnerships to establish a robust project pipeline, multiple scalable project opportunities can set up a meaningful pipeline addressing this underserved part of the market.

Brownfields and landfills shine in a cloudy solar market

Last but not least, developers looking for investment opportunities should consider solar projects built on the U.S.’ estimated 10,000 closed landfills or 80,000 brownfields and contaminated lands. These sites offer development benefits including high insolation levels, transmission access, and proximity to energy-intensive customers. In addition, saturated markets like Massachusetts, New Jersey, and Illinois offer specific economic incentives and permitting advantages for landfill and brownfield solar projects to create a “win-win” where land returns to productivity and developers generate profits.

This market vertical poses challenges like steep slopes, impenetrable surfaces, and environmental remediation costs, but it is a viable opportunity. Good development fundamentals are key here - saving time and money over the long run through understanding the required state and local permitting and inspection processes. Addressing these types of solar projects also requires an expanded view of the solar investment thesis, as project lifecycles are typically longer than with most other kinds of projects due to extended permitting and design concerns, leading to larger budgets and longer investment timelines. (To learn more about the benefits and challenges of landfill/brownfield solar, check out the cover story in Solar Industry’s February 2017 issue, titled “Putting Useless Land To Good Use.”)

The potential of landfill and brownfield solar projects has just started to be realized, and if developers focus on creating a strategic and competitive advantage now, they can get a leg up in terms of capturing market share in any geographic region.

Keep evolving with a maturing market

Although the U.S. solar market has matured, utility-scale and C&I developers can still keep absolute numbers of installations growing and find a profitable home for the influx of investment coming into the solar sector by applying traditional approaches to non-traditional verticals. Promising projects still abound for solar developers - provided we keep our eyes open for financeable opportunities and keep evolving with market dynamics.

Jesse Grossman is co-founder and CEO of renewable energy company Soltage LLC, which has invested over $300 million into more than 50 solar projects across eight states.

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On June 8, 2015, Hawaii became the first state in the nation to commit to converting its electric power supply to 100% renewable energy, with a deadline set for 2045. This goal challenges the state to tap its plentiful, natural, clean sources of power, while its utilities must build grids, interconnection infrastructure, and business models that will make these power sources accessible and affordable.

Investor-owned utility Hawaiian Electric Co. provides power to 95% of residents on five of the state’s six main islands: Hawaiian Electric Co. itself serves Oahu; its Maui Electric subsidiary covers Maui, Molokai and Lanai; and a second subsidiary, Hawaii Electric Light, serves Hawaii Island. In this article, “Hawaiian Electric Co.” will be used to refer to the investor-owned parent company, and “Hawaiian Electric utilities” will be used when referring to the parent and its subsidiaries collectively.

As of December 2016, the Hawaiian Electric utilities had, on average, achieved 25.8% of the state’s renewable energy mandate. The utilities’ power mix now encompasses customer-sited private, rooftop solar systems and grid-scale technologies, including wind, solar, geothermal, biomass, biofuels and hydroelectricity.

Increasing levels of customer-sited rooftop solar PV have created a surplus of daytime, non-dispatchable generation on all of the Hawaiian islands. The Hawaiian Electric utilities cannot directly control this behind-the-meter generation, which is effectively “must take” power. As a result, they must manage other generation resources - conventional or renewable, company-owned or private - around the output of these rooftop solar systems.

Thus, at times when an island’s grid does not have sufficient demand for all of this PV production, the utility serving that island must reduce to a minimum or turn off some of its generation - by curtailing power from utility-scale wind and solar projects - in order to maintain grid stability and reliability.

To reach the state’s goal of 100% renewable power by 2045 - and its interim goals of 30% by 2020, 40% by 2030 and 70% by 2040 - Hawaiian Electric Co. has begun to develop better ways to manage curtailed power, which otherwise is lost to the system.

Part of the solution can be found in a report the company recently filed with the state’s Public Utilities Commission (PUC). Authored by the Smart Electric Power Alliance (SEPA) and ScottMadden, the report outlines a new model power purchase agreement (PPA) that Hawaiian Electric Co. is now preparing to use for future utility-scale renewable projects.

As principal co-authors of the report, our ultimate goal for this new model PPA, called the Renewable Dispatchable Generation (RDG) model, is to convert utilities from passive takers of power generation produced by various sources into proactive asset managers. With the RDG, curtailment, if necessary, is scheduled based not on the seniority of projects - that is, the most recently commissioned projects are curtailed first - but on specific, real-time needs and costs to the system. Production by these projects is then reduced in a way that creates “headroom,” or a reserve of power, that can provide ancillary, grid support services such as frequency or voltage regulation or spinning reserves.

The RDG model also improves project economics by allocating the risk of potential revenue loss due to curtailment more equitably between renewable energy developers and utilities.

Concerns related to curtailment are not unique to the state of Hawaii. The issue has emerged in California and other states where high levels of distributed solar PV have resulted in potential curtailment of other large, lower-cost renewable assets. However, because each Hawaiian island has a grid with no interconnection to others, on top of a residential solar penetration level of more than 20%, the state far outpaces others in the magnitude of curtailment necessary to balance supply and demand.
Curtailment issues

Electricity prices in Hawaii are among the highest in the U.S. - more than twice the national average - which has given customers a compelling incentive for deploying private rooftop solar and other distributed energy resources (DERs), such as storage and electric vehicles. Hawaiian Electric Co. is forecasting that levels of customer-sited DERs on island grids could almost triple by 2030.

At the same time, the utility is planning to significantly increase utility-scale wind and solar generation on each island. Because behind-the-meter DERs meet a large portion of each island’s electricity use, the load served by utility-scale conventional and renewable resources is increasingly limited during peak sunshine hours. The result is the potential for a growing need for curtailment.

At its most basic, curtailment is the reduction of a given purchased power resource below its otherwise theoretical output level. Since variable renewable resources like wind and solar are not dispatchable by nature, their production profile cannot be modified to meet system needs without forfeiting energy production. And because each island has its own, self-contained grid that can neither import nor export power, the potential need for curtailment could be significant.

It is expected that midday distributed solar generation in Hawaii will continue to increase, which may mean that a greater percentage of new grid-scale projects (including potential community solar projects) may likely face curtailment. Without some form of mitigation, we believe that curtailment levels on Oahu could conceivably reach 10%, while estimates for curtailment on Maui and Hawaii Island range from 20% to 50%.

Traditional PPAs handle this risk in one of two ways. In the first, the utility compensates the project developer or independent power producer (IPP) only for the power actually delivered, and the uncertainty resulting from any curtailment must be absorbed by the developer or IPP. In the other - sometimes called a “take or pay” contract - the utility pays for any energy that is produced or could have been produced if not curtailed.

Either way, the dollars-and-cents impact is higher prices, with the cost of curtailment ultimately passed to customers. Specifically, developers today must account for curtailment risks within their PPAs. A utility-scale plant that would normally be priced at $100/MWh might compensate for a 20% curtailment risk by bumping up its price to $125/MWh. The higher price raises costs for utilities and customers, increases potential losses for curtailment, and may make projects harder to finance.

The RDG model: How it works

The RDG model for PPAs aims to provide renewable dispatchability while integrating high levels of DERs. Under these contracts, the utility can schedule a percentage of potential production from a renewable project, based on solar or wind resource availability on any given day, factoring in the needs of the system from both a cost and reliability perspective.

Under ideal circumstances, the contract would require a solar developer or IPP to do the following:

- Guarantee minimum availability metrics to ensure the equipment is maintained and available for production;
- Meet technical and operational characteristics that support grid operation, including voltage regulation, disturbance ride-through, frequency response, and active power control; and
- Provide an indication to the utility of the available energy in near-real time.

These guarantees form the basis for the energy production or megawatt-hours - expected for a given solar irradiance or wind speed. The utility, in turn, controls the real and reactive power output of the facility on a real-time basis. From an economic standpoint, the utility pays a fixed monthly amount to ensure the system is financeable, and a variable component, in dollars per megawatt-hour ($/MWh), to cover operations and maintenance costs - if applicable, depending upon the resource.

Any unscheduled energy, up to the amount capable of being produced given existing weather, becomes spinning reserves - unloaded generation that can be called upon in minutes. The power can also be deployed automatically, according to defined frequency response parameters.

Traditional curtailment order - under which the newest...
projects are curtailed first - would also be changed for new projects going forward. Under the RDG model, curtailment order would be based more closely on economics and system needs than on the date of first operation. For standard agreements, the PPA price is the most logical trigger for curtailment order, with flexibility outside of economic dispatch based on specific local system needs.

For example, Figure 1 shows an average day’s production for a solar plant with a nameplate capacity of 10 MW. Under the RDG structure, the utility intentionally dispatches the resource at 50% production. Later, due to greater demand, the utility increases the production to 100% in the late afternoon, as shown in Figure 2. The ability to ramp up that solar asset could create more than 3 MW of upward spinning reserves on this average day, with over 2 MW of increased generation actually leveraged between 3 p.m. and 4 p.m.

This project could also provide downward spinning reserves during all producing hours. Alternatively, that same unloaded generation could be used for regulation purposes, with inverters varying output based on the system frequency at any given moment. By purposefully under-scheduling the solar asset, the solar generator can contribute to the provision of ancillary services.

Historically, variable renewable resources have not provided these types of grid services. Adding the ability to provide spinning reserves and frequency response reduces the integration costs of adding these assets to the system, effectively increasing their overall value to the Hawaiian Electric utilities. With the utilities’ push toward a 100% clean energy future, these added capabilities may become critical to system reliability.

On the financing side, the RDG model provides guaranteed revenues - assuming the minimum requirements for a project’s availability and energy production potential are met - which should result in more certainty around debt service coverage and equity returns. Risks are therefore more equally shared between utilities and IPPs.

**Looking ahead**

Challenges remain in transitioning directly to this new contract structure from today’s paradigm. Several iterations may
be needed to refine resource forecasting and associated availability metrics and to overcome any additional operational challenges.

Research is ongoing into how customers may be affected by these new agreements. Potential unintended consequences as a result of increased fixed payments and the curtailment conditions need to be identified and further discussed.

Moving from concept to execution on this new model will also require a reshaping of utility procurement processes. Rather than focusing primarily on the lowest price for delivered energy, procurement will need to balance multiple pricing and delivery options against long-term price risk for consumers. IPPs, regulators, utility companies, and other major stakeholders will need to work together to determine how future requests for proposals will be designed. In particular, IPPs must have a clear picture of how projects will be valued, and utilities must be able to receive clear, transparent and detailed information from developers to expedite the review process.

All stakeholders will also need to agree on how to translate these new ideas into contract language. The procurement team at Hawaiian Electric Co. is now developing this language. The utility has yet to submit a project using this revised PPA for PUC approval.

Fast-evolving technology - such as energy storage - is another key variable. Hawaiian Electric Co. has already begun researching the potential for energy storage to provide fast frequency response.

This and other applications for energy storage warrant further discussion and research, as the best solution for Hawaii is most likely a holistic package of customer, developer and utility investments that are collaboratively planned. Such considerations can be part of a robust integrated resource planning process that weighs the relative pros and cons of different resources and contract structures for the benefit of all customers over the long term.

Whatever solutions are found in Hawaii will undoubtedly have a ripple effect for other U.S. utilities as they confront rising levels of solar on their distribution and transmission systems. Although the diversity of U.S. markets requires locally customized models, the message is clear: The grid of the future is evolving out of the existing system, creating a hybrid in which traditional utility and solar business models must also transition. Proactive, collaborative innovation is the new normal.

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**Other Options To Mitigate Curtailment Risk**

The Dispatchable Renewable Generation model for utility-scale solar PPAs is one of three potential approaches to curtailment explored in the SEPA-ScottMadden report, titled “Proactive Solutions to Curtailment Risk.” The other two models are the following:

**Capacity and Energy PPAs:** For these contracts, bidders would propose pricing based on two components: fixed ($/MW per month) and energy ($/MWh). Bidders would incorporate their curtailment risk outlook into the proposed breakdown between fixed and variable components. This approach provides a guaranteed income stream for developers while also reducing risk for utilities and their customers.

**Time-of-Day-based PPAs:** These contracts would be based on energy prices being lower (or negative) during expected low-load periods and higher during peak-load hours. Price caps would be set for every hour of every day of the year, taking into account seasonal variations. The uncertainty of predicting the long-term system load profile makes this option difficult to align with forecast production costs and, therefore, appropriate energy prices. Setting up and administering these contracts would also be extremely complex.
What If Federal Support For Solar Disappears?
The surprising outcome of the 2016 U.S. federal elections left many in the solar energy industry unprepared for potential changes in federal law and policy. The resultant policy uncertainty has caused some concern about what the future may hold for solar energy in the U.S., a market that has been enjoying strong year-over-year growth for the past several years. When evaluating policy and legal risk factors for the solar industry, however, it is important to consider the impacts not only of federal law, but also of state and local law.

Prior to the election, many in the industry had hoped and expected that federal policy would provide new and extended benefits for solar energy. Those hopes and expectations were dashed following the election. The Clean Power Plan will likely be dismantled by the new administration. The establishment of a carbon tax or similar carbon policy appeared to be a possibil-

Federal policy uncertainty underscores the important role states play in the solar industry.

by Morten A. Lund & Brian J. Nese

ity, but we believe that this is off the table at least until the next election.

Despite the loss of future upside, many existing federal policies remain in place. And whenever industry stakeholders discuss federal solar policy and possible changes, the first topic, without fail, is federal tax benefits for solar: namely, the federal investment tax credit (ITC) and accelerated depreciation (MACRS). These two important tax benefits can provide a tax-driven discount of 40% or more on the cost of a solar energy project.

Apart from meddling with the ITC (which was extended by Congress in 2015 and will begin to phase down in 2020) and MACRS, there are certainly other things the federal government could do that would negatively affect the solar industry in the U.S. There could be changes to the Bureau of Land Management land use policies for solar or other federal land use and permitting rules. There could be new incentives or policies favoring non-renewable energy sources. There could be changes to Federal Energy Regulatory Commission (FERC) rules or interpretations of FERC jurisdiction. But each of these is, in the grand scheme of things, relatively minor when compared with ITC and MACRS benefits, which are undoubtedly the most important federal policies for the U.S. solar industry.

The industry is just ramping up again after the recent extension of the ITC, and the common fear is that an early revocation of the ITC (or other action to reduce its value, such as changes to corporate tax rates) would send the solar industry into a steep decline. However, we contend that if the ITC disappeared, states and local governments would step in to fill the void, not necessarily through tax incentives but through other programs and policies within the scope of their powers.

We do not mean to minimize the value of the ITC or the harm that could come from its premature termination. However, current policies at the state level not only are more potent than the ITC, but in some cases, would also be unaffected by its removal. In addition, bills currently proposed in various states, as well as the overall political climate in key states, lead us to believe that states will continue to act to foster the continued expansion of solar energy.

State-level drivers

The most important state policy is the renewable portfolio standard (RPS), a powerful tool that encourages development of renewable energy projects. These laws require utilities to obtain a certain amount of energy or capacity from renewable energy resources. To date, 29 states (plus Washington, D.C., and three U.S. territories) have an RPS, while another eight states and one territory have renewable portfolio goals.

It is no coincidence that the states with the most installed renewable capacity are the same states with strong RPS policies. California has consistently increased its RPS, going from 20% by 2017, to 33% by 2020, to 50% by 2030. Recently, in what could be interpreted as a bold move by the California legislature to fill a perceived lack of federal leadership on renewable energy policy, State Sen. Kevin de Leon introduced legislation (S.B.584) that would increase the California RPS to 100% by 2045. The bill would align California with existing law in Hawaii, which passed a 100% by 2045 RPS in 2015. Similarly, proposed legislation recently introduced in Massachusetts (S.D.1932) would require the state to achieve 100% renewable electricity generation by 2035 and phase out the use of fossil fuels across all sectors, including transportation, by 2050. In Minnesota, Lt. Gov. Tina Smith recently proposed a plan to increase the state RPS to 50% by 2030.

These actions exemplify the type of impactful state law that can drive renewable energy policy in the absence of supportive federal legislation.

The most relevant feature of an RPS is that it is a pure mandate and, therefore, largely immune to specific system pricing - including price increases following a removal of the ITC. If the ITC disappeared, the cost of renewable power would likely increase, but the entities covered by most state RPS would remain obligated to purchase the more expensive power. As a result, the most impactful potential change in federal policy would have little or no lasting impact on the main state policy.

Although the RPS is by far the principal state-level policy supporting renewable energy projects, many states have also implemented state-level incentive programs over the years to support such projects. One shining example of a successful state incentive is the California Solar Initiative (CSI). The CSI was a $2 billion, ratepayer-funded solar rebate program created in 2006 with the goal of spurring the solar industry in California. Now expired, the CSI undeniably contributed to the expansive growth of installed solar capacity in California from 2006 to 2016.

State and local governments possess another useful tool for
supporting renewable energy: control over building codes. Several jurisdictions have implemented revisions to building codes to require new construction to incorporate on-site renewable generation or net zero energy consumption requirements.

In 2013, for example, the City of Lancaster, Calif., became the first U.S. city to require home builders to install solar on all new homes. And if a bill recently introduced by California State Sen. Scott Wiener (S.B.71) advances, a similar requirement may be imposed statewide.

For clear proof of the power of state policy, we need only look to see where solar is - and where it is not. Despite their relatively low solar resource, Massachusetts, New York and New Jersey are among the top solar energy states in the country. This is mostly due to their favorable state-level policies, such as RPS (which can be met through tradable certificates) and virtual net metering.

Meanwhile, Florida - one of the sunniest states in the U.S. - is not a major solar market, specifically because of the lack of an RPS, coupled with oppressive state laws regarding third-party ownership.

State policy has the power to both create and destroy markets for solar energy. In fact, in some ways, restrictive state policies could be even more detrimental than adverse federal rules. For example, a recently proposed “Electricity Production Standard” in Wyoming would have required state utilities to procure 100% of their energy by 2019 from “eligible generating resources,” which were limited to coal, natural gas, net metering (under 25 kW), nuclear and oil. This “anti-RPS” did not succeed, but if it had passed, it could have quickly destroyed the solar energy industry in Wyoming.

Moreover, we note that California alone accounted for 35% of the total U.S. solar energy capacity installed in 2016. In addition to California, other states that have demonstrated their ongoing commitment to solar energy could, through state-level action, sustain the U.S. solar energy industry for years to come. In the event of a lost ITC or other negative federal policy changes, we believe it is likely that California and other states would take action to preserve and protect solar energy and the continued growth thereof.

These incentives and programs should be viewed in conjunction with general market economics. Utility-scale solar is at or near grid parity in several regions, and commercial and residential solar is well past that point in some parts, as well. Other markets, such as Texas, are teetering on the edge, ready to explode at any moment.

Losing the ITC would have the most effect on projects and markets that compete on price, but even in those markets, the effect would be limited. Losing the ITC would probably stunt the development of the solar market in Texas and other markets that are on the fringe of grid parity. Perhaps the starker effect would be in markets that currently are, or are on the verge of, operating principally on Public Utility Regulatory Policies Act (PURPA) contracts, such as Utah, Idaho and Montana, among others. These markets would struggle. But we observe again that these PURPA markets (other than North Carolina, which until recently had a powerful state-level tax credit incentive) are relatively small. If development of utility-scale solar stopped in Montana, for example, this would not constitute a major impact on the U.S. solar industry as a whole, and development would continue on in other markets.

On the other hand, consider the impact of increased pricing on residential and commercial solar in California, for instance. The payback period would be extended (which would negatively impact the market), but residential and commercial solar in California would still be a money-saving investment for customers, and installations would continue - even without any additional boost from new or updated California state incentives. The same is true of several other states. And unlike Montana, these are the states that have been driving the industry.

In the end, this must be the conclusion: The fate of the U.S. solar energy industry likely rests with a handful of states rather than the federal government. Under a likely scenario, policies and local energy prices in those states would continue to expand the solar industry for years to come, regardless of any likely federal action. Federal policy changes may slow or hinder growth in second-tier solar states, as well as geographic expansion to new markets - but the solar industry is too mature and too well supported where it matters to be crippled by any reasonable action at the federal level.

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Clearly, the global energy landscape is changing at an exponential rate. In the U.S. alone, the solar energy market had a momentous year in 2016, nearly doubling the country’s previous installation record set in 2015. Despite expected changes in the U.S. federal government’s focus on renewable energy, it is predicted that solar power will remain a significant source of both new clean energy capacity and new jobs in 2017 and beyond. Soon, this trajectory will be impossible to ignore. As solar PV installations continue to increase, the materials that help fuel these installations will be impacted, as well.

Copper is essential to powering solar PV systems and other clean energy technology, including wind turbines, energy storage systems and electric vehicles. A wind farm can contain between 4 million and 15 million pounds of the metal used for generators, wiring, tubing, cable and step-up transformers. The surrounding infrastructure that connects this technology to the electrical grid also uses copper to run reliably and efficiently.

With regard to PV systems, copper is vital for the collection, storage and distribution of solar energy. Copper’s natural properties of high conductivity and durability increase the efficiency and performance of photovoltaic cells and modules. It is relied upon to conduct amperes and to connect voltages to the grid; in some cases, copper is needed to drive motors that tilt the solar panels toward the sun. A well-designed solar PV plant might use approximately 9,000 pounds of copper per megawatt of peak capacity - a figure that does not appear to vary significantly over installations ranging from large rooftop units to multi-megawatt utility farms.

The red metal has long been known for its use in traditional electrical generation. Copper wire and cable power homes and buildings, fuel the electrical grid, and are used in electrical transformers and motors. What many people don’t know is that copper plays an even greater role in renewable energy technology. Copper usage in renewable energy technology varies between each system, but on average, it is up to five times greater than in traditional electrical generation. In addition, copper is also used to connect these systems to energy storage installations and to the larger electrical grid.

Copper, itself, is a sustainable material for a variety of reasons. The metal used in solar PV and other renewable energy systems is not consumed. In fact, copper is 100% recyclable and can be used and reused after the lifecycle of a PV system without losing its beneficial properties, such as high conductivity and durability. Each year in the U.S., nearly as much copper is recovered from recycled material as is derived from newly mined ore. When you exclude wire production, most of which uses newly refined copper, nearly three-fourths (72%) of copper used by copper and brass mills, ingot makers, foundries, powder plants, and other industries comes from recycled copper scrap.

Copper also increases the electrical efficiency of the technology that it powers. Its electrical conductivity is virtually...
unmatched by any other engineering metal. This property, combined with copper’s ability to create high-quality, low-resistance connections, is the basis for highly efficient electrical equipment and lower energy losses.

Continued growth in the solar PV market presents a unique usage opportunity for copper. Following its record-breaking growth in 2016, the U.S. solar market is expected to continue expanding. Although the Obama administration largely supported renewable energy projects as a response to climate change, the Trump administration will likely be more interested in the renewable energy sector’s potential to grow jobs and increase American exports. Meanwhile, U.S. states and large corporations around the world are pledging to pick up the mantle of environmental conservation and climate science. In fact, almost 90 leading companies, including Google, Facebook, Apple, General Motors and Coca-Cola Enterprises, have committed to source 100% of their energy from renewables under the global RE100 initiative. The demand for solar PV—and, thus, for copper—will be impacted as this trend continues.

For its part, the copper industry has embraced its important role in sustainable energy and is helping to work toward a greener future. In January, for example, the International Council on Mining and Metals announced new commitments on water stewardship that support the responsible use of water. In addition, other industry organizations study clean energy applications and support initiatives that seek to increase the use of renewable energy technology.

Through outreach and engagement with the U.S. Department of Energy (DOE), the copper industry identifies research and development projects pertaining to renewable energy, electricity delivery and advanced manufacturing. This relationship building has resulted in a number of opportunities for both associations and individual copper producers. For example, in October 2016, Rio Tinto, one of the world’s largest mining corporations, announced a partnership with the DOE’s Critical Materials Institute to aid in the recovery of critical materials and minerals. This research project will work to ensure that the U.S. fully leverages domestic resources, such as copper, that are essential to clean power manufacturing.

The European copper industry has embraced the United Nations’ Sustainable Development Goals and has developed strategies to support significant carbon reductions in the downstream industrial, residential and service sectors. By 2020, these strategies could deliver 130 million tons of CO2 savings per year. The European Copper Institute report, “Copper’s Contribution To A Low-Carbon Future - A Plan To Decarbonize Europe By 25 percent,” outlines specific copper-based technologies triggering CO2 reduction, including motor and transformer efficiency and solar thermal technologies. It also outlines reduction opportunities within the copper industry.

As renewable energy technology and solar PV systems, in particular, become the “new normal” both in the U.S. and abroad, copper will be increasingly utilized. It is trusted to power these systems efficiently and to reliably connect them to the larger electrical grid. Whether in energy storage systems, solar panels, electric cars or transformers, copper is essential to the world’s energy supply. The copper industry is proud of the role it has to play in renewable energy and is committed to supporting a more sustainable future. As solar PV systems continue to become more affordable and competitive with fossil fuels, the market for this technology will have a strong impact on the demand for copper products.

Zolaikha Strong is director of sustainable energy for the Copper Development Association.
P roving yet again that compromise does, in fact, work, Arizo

na’s largest electric utility and solar advocacy groups have reached a major settlement agreement that lays to rest several contentious issues. As with all compromises, each party didn’t get exactly what it wanted, but the future of rooftop solar in Arizona looks a bit brighter.

When utility Arizona Public Service (APS) filed a rate case with the Arizona Corporation Commission (ACC) in June 2016, solar proponents geared up for a fight. The APS proposal called for mandated demand charges for all residential ratepayers, including both solar and non-solar customers, and sought to eliminate retail net energy metering (NEM) for rooftop solar customers.

Rather than fight an ugly battle, though, the utility and solar groups have successfully negotiated a settlement agreement. The ACC is expected to vote on the compromise this summer.

Sean Gallagher, vice president of state affairs at the Solar Energy Industries Association (SEIA), says, “After weeks of discussion, we are pleased negotiations produced a settlement that all stakeholders, SEIA included, feel comfortable signing. The thorough process concluded outside of litigation, and we hope an era of collaboration will take hold in Arizona.”

“This agreement demonstrates what can be accomplished when people come together with a willingness to compromise and resolve complex policy issues,” states Don Brandt, president and CEO of APS. “The winners are Arizona electricity customers.”

If approved, the deal would scrap APS’ plan for mandated demand charges, which some solar advocates argue are confusing and hinder market growth. Rather, APS residential customers would have a variety of rate options from which to choose, including a time-of-use (TOU) rate, two optional demand rates and a pilot demand rate. Rooftop solar customers who select a TOU rate plan will also have a grid access charge.

“Arizona’s families and businesses should be able to meet their own energy needs with the state’s plentiful sunshine if they so choose,” says Briana Kobor, director of the distributed generation regulatory policy program at nonprofit Vote Solar. “We were glad to arrive at a settlement that takes some steps to preserve customer choice, keeps solar customers on the same rates as other customers, and soundly rejects the idea of penalizing all residential customers with mandatory demand charges.”

In its original filing, APS also took aim at NEM, which compensates rooftop solar customers for their excess energy and has stirred debate in Arizona for years. Specifically, the utility wanted to slash the NEM credit from about 14 cents/kWh, the retail rate, to about 3 cents/kWh, the wholesale rate.

At the time, APS’ Brandt called the proposal “pro-solar and pro-customer” and said, “We want to continue Arizona’s solar leadership the right way - with more solar, for more customers, without driving up the energy bills paid by non-solar customers.”

However, after a three-year probe into the value of solar, the ACC voted to end the state’s NEM program and replace it with a lower export credit rate in December 2016 - thus superseding APS’ NEM request in the utility’s pending rate case.

Nonetheless, solar advocates were able to reach a seemingly good compromise with APS within the confines of the ACC’s new rules.
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First, the settlement includes a policy resembling grandfather clauses included in the ACC plan and the original APS request: APS rooftop solar customers who file an application before the ACC’s settlement approval would be grandfathered in under their current retail NEM rates for 20 years from their interconnection date.

Second, under the settlement, APS would compensate future rooftop solar customers with an export credit rate beginning at 12.9 cents/kWh - that’s certainly much higher than the 3 cents/kWh rate APS proposed in its original filing. Customers would lock in their rates for 10 years whenever they sign up, providing some long-term certainty, but the available rate for new solar customers would decline by up to 10% annually.

“While the solar industry didn’t get everything it had hoped for out of the settlement, Arizona’s current solar customers can rest assured they will be grandfathered into their existing rates, which was a priority for SEIA,” explains Gallagher. “Under the agreement, new solar customers will be able to sign up under initial rates that are as favorable as could be obtained under the commission’s December 2016 Value of Solar decision, which creates longer-term uncertainties for Arizona customers.”

Brandt says the deal “continues Arizona’s solar leadership with smart policies that enable the continued growth of solar and other new consumer technologies while protecting non-solar customers.”

Anne Hoskins, chief policy officer at residential solar provider Sunrun, says the settlement is “more proof that rooftop solar is inevitable” but claims the agreement “does not fully recognize the multitude of benefits that rooftop solar brings to all Arizonans.”

“While Arizona does not serve as a model to encourage innovation in distributed energy, we are pleased that, together, we have ended years of debate on the future of rooftop solar policy in Arizona,” she adds.

Under the settlement, APS would also invest between $10 million and $15 million annually in AZ Sun II, a new program for utility-owned rooftop solar on customers’ homes meant to benefit low- and moderate-income residents. - Joseph Bebon

**Alberta Govt. Aims For 10,000 New Solar Rooftops**

In the U.S.’ neighbor to the north, the Canadian province of Alberta is aiming to support 10,000 new rooftop solar installations by 2020 and create more local solar jobs.

To help achieve that goal and longer-term solar market growth, the Alberta government has launched the Residential and Commercial Solar Program, a five-year rebate program to subsidize the installation of solar electricity generation atop residential and commercial buildings across the province. The government has allotted an initial C$36 million for the first two years of the new program.

In a press release, the government says solar uptake has doubled in Alberta since 2015, bolstered by initiatives such as the Alberta Municipal Solar Program and the On-Farm Solar PV Program. Over the next five years, the Residential and Commercial Solar Program will build on these existing
programs, as well as play a major role in reaching the near-
term goal of 10,000 new installations.

“There’s a lot of buzz in Alberta around small-scale solar. This program will make solar power affordable for more Al-
bertans, leading to new panels on 10,000 Alberta rooftops by 2020. Along the way, we will create jobs and local expertise in an emerg-
ing industry,” comments Shannon Phillips, Al-
berta’s minister of environ-
ment and parks and minister responsible for the climate change office.

The Alberta govern-
ment says homeowners,
businesses and nonprofit organizations will receive rebates for rooftop solar panels that meet the program requirements as early as this summer. In its first two years, the Residential and Commercial Solar Program is expected to support the creation of 900 jobs in Alberta’s solar sector; cut solar installation costs by up to 30% for residences and up to 25% for businesses and nonprof-
its; and significantly reduce greenhouse-gas emissions in the province.

To ensure Albertans receive timely access, the government is posting a request for proposals to identify a third party to deliver the new program. Details will be defined in coming months, including qualifying systems, installation and eligibility requirements.

The Canadian Solar Industries Association (CanSIA) says the country’s solar industry is primed to participate Alberta’s new program.

“Alberta, a province best known for its oil and gas industry, is also rapidly becoming west-
ern Canada’s leader in renewable energy,” says John Gorman, president and CEO of CanSIA. “The government of Alberta is positioning the province for the diversification of its energy fu-
ture by exploring another one of its abundant energy sources - the sun. More Albertan house-
holds and small businesses will now be empowered to go solar, strengthening local economies and creating jobs. The govern-
ment has delivered on their word, and the Canadian solar in-
dustry is ready to deliver in return.”

El Paso Electric Targets Rooftop Solar Again

Despite reaching a settlement agreement with solar stake-
holders last year, Texas-based utility El Paso Electric (EPE) is revamping efforts to change the rules for rooftop solar cus-
tomers and impose new charges.

The solar plans are included in EPE’s broader 2017 Texas rate case, which seeks to increase prices for ratepayers. The company, whose service territory also includes parts of New Mexico, filed its rate case with the Public Utility Commission of Texas and other relevant authorities in the Lone Star State. According to an EPE press release, the utility is requesting “an increase in non-fuel base revenues of approximately $42.5 million. Under the proposed rates, a residential customer using 635 kWh per month will see an average bill increase of $8.25 per month when new rates are implemented.” The utility says the increase is necessary in order to help pay for grid improve-
ments and recover costs associated with a natural gas plant in Texas.

“We’ve worked hard to modernize our aging local genera-
tion fleet and promote solar and other clean energy technolo-
gies our customers want - all while providing safe, reliable and affordable service,” comments EPE CEO Mary Kipp in the release. “We spend a lot of time planning how to best meet the demands created by the continued growth of our region, and these latest investments will benefit our customers well into the future.”

Notably, EPE officially became coal-free last year and said it was increasing its focus on cleaner energy resources, including solar. However, the utility is again proposing to create a separate rate class for its rooftop solar customer.

In its announcement, EPE claims the new structure would “reflect the unique service characteristics and cost of service for this group of customers” and include a new monthly demand charge “to recover the cost of grid-related services.”

In the release, Kipp comments, “It is important to estab-
lish a fair rate structure that reflects the cost to serve each customer class. As technologies evolve and our customers’ needs change, we must also evolve to provide programs and rate structures that allow us to provide safe and reli-
able service at a price that is fair to all our customers.”

According to an EPE fact sheet on its website, the pro-
posed solar provisions would increase a residential solar customer’s monthly bill by $14.09, on average. The utility says it has also proposed “identical” rate structure changes for small commercial customers with rooftop solar.

EPE made similar requests targeting rooftop solar custom-
ers in its 2015 rate case, but the utility eventually dropped the controversial plans under a settlement agreement with solar industry stakeholders in 2016. The Alliance for Solar Choice (TASC), one of several advocacy groups that championed the compromise, seems none too pleased with the utility’s newest proposal.
“Demand charges found unreceptive audiences among regulators in 2016, and last year, Texas residents clearly rejected El Paso Electric’s same drastic and unprecedented rate design that punishes solar customers,” says TASC spokesperson Amy Heart. “EPE is attempting to circumvent Texas policymakers and citizen directives to support solar growth and competition by implementing confusing charges that have been rejected across 14 states and counting. It is time EPE focuses on integrating solar opportunities and customer choice, rather than force anti-consumer rate design on Texans.”

In addition to TASC, at least one Texas legislator has spoken out against the 2017 rate case. State Sen. José Rodríguez represents District 29, which includes El Paso County and some other Texas regions, and he charges the new rate case includes “anti-solar proposals” that raise “similar concerns” the senator had with EPE’s 2015 case.

“I’m disappointed that El Paso Electric insists on discouraging people from installing solar on their homes,” says Rodriguez in a press release. “The electric company once again wants to single out solar customers by increasing their rates at least two times the amount of their non-solar neighbors. Solar customers will no longer be able to save on their electric bills, which was the reason they installed solar panels in the first place.”

In its fact sheet, EPE notes the 2017 Texas rate case decision could take up to a year, and the utility says it has “met with several interested parties since the 2015 rate case, and conversations will continue throughout this rate case process.”

- Joseph Bebon

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**Policy Watch**

**NV Energy Proposes Customer ‘Subscription Solar’ Program**

Although the Nevada utility has long been under fire for its questionable support for customer-owned rooftop solar, NV Energy has announced it is seeking regulatory approval for a program that would allow its customers to sign up for and purchase some utility-owned solar.

According to NV Energy, the new Subscription Solar program would give residential - and, eventually, small to mid-size business customers - the option to meet up to 100% of their energy needs with renewable energy.

“NV Energy is committed to a cleaner energy future, and that includes finding ways to deliver solar and renewable energy conveniently to our customers,” says Pat Egan, senior vice president of renewable energy and smart infrastructure for NV Energy. “Our Subscription Solar program gives our customers a choice when it comes to their energy mix - providing them with a simple, flexible and affordable way to reach their sustainability goals.”

If the program is approved as filed by the Public Utilities Commission of Nevada, eligible customers will be able to subscribe monthly to 100 kWh “blocks” of solar energy. NV Energy explains customers can subscribe to a minimum of one block up to an amount of blocks not to exceed their average monthly usage.

“This program is specifically designed for customers who may not have access to a rooftop but who would like a low-cost, renewable energy option or for those whom building their own rooftop system isn’t a great option,” says Egan.

The projected cost per block is $2.00 per month, which NV Energy says would make its Subscription Solar program one of the lower-cost programs of this type in the nation. This is in addition to a customer’s normal monthly bill. For example, if a customer in an apartment using 600 kWh a month desired to be 100% “green,” he or she would subscribe to six blocks for a monthly premium of $12, plus applicable taxes and fees. The utility notes the Subscription Solar program does not require any long-term contracts or upfront investments, and there are no cancellation fees or participation period commitments.

NV Energy has designated 10 MW of solar energy from the Boulder Solar I facility to meet the initial needs of the Subscription Solar program. NV Energy, in conjunction with Apple, also designated an additional 5 MW of the Techren II facility, which is projected to be operational in 2019.

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Solar Savings Will Help Foodbank Feed More Hungry Families

The Hawaii Foodbank and REC Solar have celebrated the installation of a new solar array at the nonprofit's Oahu warehouse. REC Solar says the 296.7 kW solar system is estimated to save the Hawaii Foodbank about 463,742 kWh of energy in the first year - equivalent to the purchase of over 102,000 meals, feeding 93 people daily over the course of one year.

“We are proud to have such a large-scale solar installation at the Hawaii Foodbank,” comments Gerald Shintaku, the nonprofit’s president and CEO. “This new technology will reduce our energy costs significantly and will allow us to serve more hungry families while also contributing to a more sustainable environment on Oahu.”

According to REC Solar, Hawaii Foodbank’s new solar system is projected to save the nonprofit about $41,041 in energy costs during the first year of installation and approximately $2.1 million over the next 25 years.

“It is an honor to be involved in a project where solar power is being used to offset operational expenses and will ultimately help provide more meals for those in need,” says Alan Russo, senior vice president of sales and marketing at REC Solar. “We are proud of our work with the Hawaii Foodbank, and we look forward to continuing our tradition of providing green energy solutions to other local organizations.”

EPB Breaks Ground On Community Solar Project

EPB, a municipally owned utility in Chattanooga, Tenn., has started construction on the city’s first community solar installation.

Dubbed Solar Share, the community solar project is a partnership between EPB and the Tennessee Valley Authority (TVA), and the solar facility will be located along Holtzclaw Avenue at EPB’s Distribution Center. By summer, Solar Share is expected to begin generating 1.35 MW of solar power, which EPB says is enough to meet the needs of about 200 households that consume an average amount of power.

“EPB is proud to establish Solar Share as a lasting community asset, which will generate renewable energy for years to come,” says EPB Board of Directors Chairman Joe Ferguson.

According to David Wade, president and CEO of EPB, Solar Share was designed to lower the barriers to entry for customers interested in solar power.

“Community solar is like joining a community pool rather than excavating your yard and installing a pool on your own property,” says Wade. “The benefits are enjoyed by many more people, who don’t have to worry about maintenance, liability and other hassles. Participating in Solar Share is a great option for people who live in apartments and other situations where solar panel installation is not feasible.”

“TVA is committed to providing renewable energy in a way that maximizes the benefits to the communities we serve,” adds the TVA’s Cindy Herron. “Working with EPB to bring Solar Share to Chattanooga is a great example of what can happen when communities and utilities come together for a common goal: a cleaner future.”

After a competitive bidding process, EPB selected TVA Energy LLC - Tennessee Valley Alternative Energy - as its partner to construct Solar Share.

SunPower Project To Create About 300 Jobs In Oregon

SunPower Corp. has kicked off construction on the 56 MW AC Gala Solar Power Plant in Crook County, Ore. The project, which is expected to be the state’s largest operating solar power plant when completed by the end of 2017, is anticipated to create approximately 300 jobs during peak construction.

In a press release, Gov. Kate Brown, D-Ore., remarks, “I’ve often said that, in Oregon, we don’t believe economic development and environmental stewardship are mutually exclusive ideas. The approximately 300 jobs expected to be created by the Gala Solar Power Plant are proof we can grow our rural communities and support a vibrant and innovative renewable energy industry.”

Brown has been a prominent supporter of clean energy: Last year, for example, the governor signed a bill that increases Oregon’s renewable portfolio standard to 50% by 2040 and will
eliminate the use of coal in the state. Utility-scale solar projects like the Gala plant will help Oregon meet its clean energy goals.

“Solar power projects deliver a range of regional benefits, including job creation and affordable, emission-free power,” says Ann Beier, assistant planning director of Crook County Community Development. “We are proud that, working in partnership with SunPower on the Gala Solar Power Plant, Crook County is helping lead the way in Oregon in supporting increased solar development.”

The Gala solar project will feature the third-generation SunPower Oasis platform, which SunPower claims includes 50% fewer parts than conventional solar plant systems and an integrated solar tracker design that streamlines construction and reduces operations and maintenance costs.

“While solar is cost-competitive today, SunPower is continuing to drive the cost of energy down through innovation and integrated complete solutions such as our Oasis platform,” says Ty Daul, SunPower vice president of Americas power plants. “We’re pleased to contribute to economic development in Oregon with the construction of this milestone project.”

SunPower has contracted construction firm Moss to serve as the general contractor for the project.

Mass. Schools, Town To Benefit From Brownfield Solar

Renewable energy company Soltage LLC and independent power producer Tenaska have completed a 3.68 MW ground-mounted solar project in Billerica, Mass.

According to the companies, the project is located on a brownfield site and will generate 4,445 MWh of clean energy annually for four school systems and one local government through 20-year virtual net-metering credit agreements. Project off-takers include the Town of Barre, Mass.; the Tantasqua Regional School District; the Wachusetts Regional School Dis-

Duke Energy Indiana’s First Solar Project Goes Online

Duke Energy Indiana says its first large-scale solar power plant is now in commercial service and sending clean, renewable energy to customers throughout the utility’s 69-county service territory.

The plant, which can generate as much as 17 MW of alternating-current power, is located at Naval Support Activity Crane (NSA Crane), approximately 40 miles south of Bloomington, Ind. When operating at full capacity, the solar power plant can provide electricity for more than 2,700 average-size homes.

“This is a landmark development in renewable energy for our company and our customers,” says Melody Birmingham-Byrd, president of Duke Energy Indiana. “It demonstrates our continuing commitment to include renewable energy, such as solar, wind and hydro, in our diversified portfolio of generation sources.”

The plant comprises approximately 76,000 solar panels on about 145 acres of land the company has leased from the U.S. Department of the Navy (DON). Duke Energy Indiana says the solar facility contributed to the DON meeting its goal to bring 1 GW of renewable energy into procurement by the end of 2015.

Duke Energy Indiana notes that its operations provide about 6.8 GW of owned electric capacity to approximately 810,000 customers in a 23,000-square-mile service area.

GE And Juhl Partner On Hybrid Wind-Solar Project In Minn.

GE Renewable Energy has been selected to supply equipment for what it says will be the first commercial integrated solar-wind hybrid power generation project in the U.S.

The project is located on a 553-acre brownfield industrial complex that included manufacturing and rail yard maintenance facilities, open storage areas, landfills, and former wastewater lagoons surrounded by residential properties and wetlands.

The companies say power generated by the project’s 11,204 PV panels is expected to supply an average of 20% of the off-takers’ electricity needs at costs below local utility rates and offset nearly 6.9 million pounds of carbon dioxide, the equivalent of burning more than 3.3 million pounds of coal, annually. Because it was developed on a brownfield, the project also qualifies for the third-highest incentive levels under Massachusetts’ solar renewable energy credit II program.

Tenaska is the primary investor in the solar facility, with Soltage acting as the power plant co-owner and operator.
GE will also provide its Wind Integrated Solar Energy technology platform, developed through the company’s global research center. The platform will integrate the solar panels through the wind turbine’s converter directly.

According to GE, the hybrid design will enable the project to produce power when it is most needed: Basically, the solar provides summer peak energy, and the wind provides winter peak energy.

“Most energy experts agree that distributed generation will play a major role in the implementation of renewable energy in the U.S. electrical market in the years to come,” says Dan Juhl, CEO of Juhl Energy. “Juhl Energy’s package design with the GE hybrid technology can economically blend clean, renewable energy into the grid at lower cost, plus add reliability to the system.”

Pete McCabe, president and CEO of onshore wind for GE Renewable Energy, adds, “By leveraging the complementary nature of wind and solar, this unique project shows how GE is driving technology innovation that will help customers deliver more renewable energy in an even more efficient manner.”

Cinemark Movie Theater In N.J. Goes Solar

Maryland-based Urban Grid has completed a 655 kW solar project for a Cinemark movie theater at the Cooper Towne Center in Somerdale, N.J.

Urban Grid secured a lease with National Realty & Development Corp., the building owner, for the roof space and developed and financed the project through a power purchase agreement with movie theater company Cinemark USA Inc. for its Somerdale location. Sale of the electricity produced from the 655 kW array will offset the theater’s energy requirements and provide a hedge against potentially volatile energy prices into the future.

“Urban Grid is excited to collaborate with such a highly reputable company as Cinemark to further spotlight our commitment to a sustainable future in New Jersey, a state that has seen incredible solar growth over the past few years,” remarks Frank DePew, president and CEO of Urban Grid. “We believe rooftop solar is a natural fit for businesses and hope Cinemark’s initiative will pave the way for commercial companies throughout the nation.”

SolarAmerica provided engineering, procurement and construction services for the project. The 1,957-panel solar array is expected to produce 860 MWh of electricity in its first year of operation, offsetting a significant amount of Cinemark’s electric usage at this location.

Utility-Scale Installation Comes Online In Indiana

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Duke Energy Indiana notes that its operations provide about 6.8 GW of owned electric capacity to approximately 810,000 customers in a 23,000-square-mile service area.
Adapting To DG Project Financing Changes

The financial picture for distributed solar projects is in the midst of a substantial evolution. Deals are getting more complex. Transactions have started to involve more players, new issues have arisen, and the total revenue available from a project has decreased due to falling power off-take prices. The following are three considerations you should take into order to adapt to these changes:

1. Fill out and optimize the capital stack.

When the solar industry started to take off, developers had a hard time raising capital to cover the cost of a project. At best, a developer could expect only to raise tax equity (investments in which the primary source of return was benefits). These transactions only covered 35% to 50% of the capital stack. The rest of the project cost was covered with the developer’s equity. There were no other partners, and there was no debt.

Some developers make the mistake of assuming a simple structure copied from earlier transactions will work today. But, with margins coming down, it is ever-more important to take a more sophisticated approach. Most projects now have either project-level debt or back-leverage, at a minimum. Back-leverage is debt that is subordinate to the tax equity - the only security is the developer’s interest in the partnership with a tax equity investor.

Consider equity participants that can buy into a developer’s cashflow stream at a lower weighted average cost of capital. New entrants are coming to the market every day. Insurance companies are a popular source. Many have recognized the stable cashflow stream and diversification of distributed solar. Some banks and funds will offer a similar mezzanine debt product, which we call “back-back leverage,” as it sits behind other debt in the transaction.

Each rung of the capital stack needs to be set up such that you can extract the most value from it. Separate cashflows for each capital source as much as possible.

2. Don’t blindly cost cut.

Distributed projects are the hardest to finance. They have the diligence needs of a utility-scale project without the economies of scale. Many assume this means they should cut all costs at all costs. It does not. Sloppy project documents will sour the economics of an otherwise good project. Make sure you have a crisp site lease and off-take agreement. Try to follow the Department of Energy forms, at least as a base. We see many distributed deals in which the project documents need to be reworked (and recalcitrant off-takers); this often leads to an unfinanceable project.

Community solar in the right jurisdictions offers a good way to address this issue, as power prices are closer to retail rates for these projects.

3. Recognize political risk on the horizon.

It is important not to be blindsided by looming law changes. There is always some degree of betting the curve when pricing off-take. Typically, this means betting that costs will come down is not a sure thing. The price you bid for the power contract may be out of the money if development or operation costs end up higher than expected. Do not assume they cannot go up.

Several states and utility districts have advanced plans to make it more difficult to connect distributed projects to the grid. A deal can still be financeable in a jurisdiction where these initiatives are contemplated, but they have to be understood when you are negotiating the off-take arrangement.

The Trump election has brought the possibility of tax reform into the foreground. It is likely that the corporate tax rate will decrease. For solar, this means that depreciation could be worth less. Buyers and lenders have started to change the way they price transactions. Many will assume a 20% or 25% tax rate in the model.

John Marciano III heads the Washington, D.C., office of Akin Gump Strauss Hauer & Feld’s renewable energy practice. His colleague Ed Zaelke also contributed to this piece.
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