

PROJECT FINANCE

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PURPA Projects Become More Difficult to Finance

by Caileen Kateri Gamache, in Washington

Independent cogeneration and small renewable energy projects known as “qualifying facilities” or “QFs” may lose key protections from merchant risks that they have relied on to help secure financing for the past 40 years if the Federal Energy Regulatory Commission has its way.

FERC proposed a number of changes in how it implements the Public Utility Regulatory Policies Act of 1978 on September 19. (For background, see “PJM Capacity, Grid Reliability and PURPA” in the August 2019 *NewsWire*.)

There are six main changes.

FERC would revoke the requirement that utilities offer QFs power purchase agreements with fixed prices.

It would release utilities from any obligation to purchase electricity from small solar and other renewable energy projects that are less than 20 megawatts but greater than one megawatt in size.

It would reduce the amount of electricity utilities must purchase in states that allow retail customers to choose their electricity suppliers.

It would require developers to prove commercial viability and a financial commitment to construct before a utility is required to sign a PPA. */ continued page 2*

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IN OTHER NEWS

PREPAID POWER CONTRACTS may have gotten a new lease on life in proposed regulations the IRS issued in September.

In a prepaid contract, the customer pays the electricity supplier in advance for electricity to be delivered over time. Such arrangements are also used for gas supply agreements. The structure had been used mainly where electricity or gas is supplied to a municipal utility or cooperative that has a lower cost of capital than the supplier. (For more detail, see “Prepaid Power Contracts” in the September 2012 *NewsWire*.)

The 2017 tax reforms appeared to shut down such arrangements by requiring the electricity or gas supplier to report the */ continued page 3*

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It would make it easier for people to challenge the QF status of a project. Utilities have no obligation to purchase electricity from any project unless the project is a QF.

Finally, FERC proposes to eliminate a “one-mile rule” that treats wind turbines or other facilities more than one mile apart as separate projects for purposes of the QF size limits. Affiliated projects that are between one and 10 miles apart may lose QF eligibility as a result.

The consequences for the independent power market are numerous.

Fixed Prices

The Public Utility Regulatory Policies Act is a 1978 statute that gave birth to the independent power industry in the United States. Congress adopted it after the Arab oil embargo in the 1970s to create a market for electricity from two types of power projects: cogeneration facilities that produce two useful forms of energy — for example, steam and electricity — from a single fuel and small power projects under 80 megawatts in size that use renewable energy or waste fuels.

PURPA requires utilities to buy electricity from eligible projects — QFs — at the “avoided cost” the utility would pay to generate the electricity itself.

State utility regulators determine the avoided costs of utilities in their states.

Under current FERC precedent, a QF can choose whether it wants the utility’s avoided cost rate at the time the purchase obligation is created, or at the time the electricity is delivered.

This accommodates different developer preferences. A developer primarily in the business of selling electricity normally selects the avoided cost at the time the commitment is made, because it translates to a PPA with a predictable revenue stream. In contrast, a developer who plans to sell primarily to a host customer, and thus already has a stable revenue stream, may be fine with the rate at the time of delivery to the extent it sells any excess electricity to the local utility during customer outages or other load reductions. The utility payment might even be in addition to continuing payments from the customer, depending upon the terms of the PPA.

FERC is proposing to eliminate the requirement that utilities enter into a PPA with a fixed avoided cost rate established at the outset.

Instead, states would be free to limit the avoided cost rate to a variable rate determined at the time electricity is delivered.

In wholesale markets, FERC suggests this could be the locational marginal price, called the LMP. In other markets, the avoided cost at the time of delivery could be the “competitive prices from liquid market hubs or calculated from a formula based on natural gas price indices and specified heat rates.” In other words, the avoided cost may simply be the price a QF would otherwise receive on a merchant basis. States would have latitude to invent other approaches for determining the avoided cost.

This proposal is probably the most troubling for developers who depend on third-party financing because it will make the revenue stream under PURPA contracts with utilities more unpredictable. There is debate about how important PURPA contracts remain in the current market. (See “PURPA and Solar” in the April 2017 *NewsWire* and “New Technologies and Old Issues Under PURPA” in the February 2018 *NewsWire*.)

Nevertheless, if adopted, the FERC proposal could trigger more growth in the financial hedge market by QFs seeking to put a floor under electricity prices to help with financing.

However, it may never become law. It is unreasonable to suggest the spot market price is a utility’s avoided cost required by the statute, because utilities have an obligation to procure

FERC is proposing changes that will make it harder to finance future PURPA projects.

electricity to serve load and they do not leave that obligation to market volatility. Although the proposal may be the most widely alarming among developers, it is also probably among the most likely to fail as contrary to law.

Size Limit

Congress amended PURPA in 2005 to lighten the obligation for utilities to buy power from QFs above 20 megawatts in organized markets. Congress felt that independent generators in such areas have other options than forcing a utility to buy.

The wholesale purchase obligation does not apply in any area where FERC finds QFs have “nondiscriminatory access to” transmission, interconnection and wholesale energy markets. This includes a “meaningful opportunity” to sell “to buyers other than the utility to which the qualifying facility is interconnected.” QFs that are 20 megawatts or smaller in size enjoy a rebuttable presumption that they lack non-discriminatory access. FERC is now proposing to reduce this presumption for QFs using renewable energy from 20 megawatts to one megawatt.

The decrease would probably have the greatest impact on developers in the commercial and industrial — C&I — solar market. Lenders to such projects have taken comfort from the fact that the local utility has to buy the electricity in the event a C&I customer defaults. The project might still be able to sell into the wholesale market, but that usually requires significantly greater energy market sophistication and resources than selling to the local utility. Typically, the seller would be required to register with the market, post collateral to engage in market activities, make market settlement and scheduling arrangements, and possibly obtain transmission service or related products to hedge against transmission congestion. All of this adds to the risk profile of a project.

The proposal to release utilities from the obligation to purchase power from small solar and other renewable energy projects that are above one megawatt, but less than 20 megawatts, in size is limited to the organized wholesale markets operated by regional transmission organizations and independent system operators, but FERC wants comments on whether to test the concept more broadly.

States with Retail Choice

FERC is proposing to release utilities from any purchase obligation in states that allow retail competition.

In these “retail choice” states (comprised largely of northeastern states with a few outliers, / *continued page 4*

full prepayment as income immediately upon receipt or at best partly upon receipt and the balance the next year. The structure had appeal only if the supplier could stretch out the income over the period the electricity or gas is delivered. (For more detail, see “Final US Tax Bill: Effect on Project Finance Market” in the December 2017 *NewsWire* and “Prepaid Power Contracts” in the December 2018 *NewsWire*.)

The proposed IRS regulations to implement the 2017 tax reforms make a number of exceptions.

One was in the 2017 law when it passed Congress and applies to advance payments received under “financial instruments (for example . . . forward contracts . . .).” The scope and consequences of this exception remain unclear.

The other exception is new. It covers advance payments received at least two tax years before the tax year when the prepaid electricity or gas is delivered. For example, it would apply to an advance payment received by a calendar-year electricity or gas supplier in 2020 for electricity or gas that will not be delivered until 2022 or later.

This is a so-called specified-goods exception, and there are two other conditions to fit in it. First, the supplier cannot have “on hand (or available to it in [the year the advance payment is received] through its normal source of supply) goods of a substantially similar kind and in a sufficient quantity to satisfy” the contract. Second, the supplier must wait to report the prepayment as book income as the electricity or gas is delivered.

If prepayments for electricity or gas sold under long-term contracts do not have to be reported immediately as income or at best deferred for only a year, then this begs the question how such payments should be reported.

The proposed regulations suggest they should be reported over the same period they accrue for tax purposes, / *continued page 5*

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and notably Texas), utilities' obligations to purchase would be reduced to the same extent as their obligation to serve load is reduced by competitive energy suppliers.

If the utility has an obligation to provide electricity in the event a customer cannot obtain retail service — in other words, act as a “provider of last resort” — any PURPA contract the utility is required to sign would not have to run longer than the period it must act as a provider of last resort. Provider-of-last-resort requirements are often limited to one-year commitments.

The changes would also make it harder for projects to qualify for PURPA contracts.

Proving Commercial Viability

FERC is proposing to require QFs to demonstrate “commercial viability” and show a “financial commitment to construct” before a utility is required to sign a PPA with the project.

Each state would establish its own “objective and reasonable” criteria for evaluating whether the requirement is satisfied. FERC proposed examples of things developers might have to prove to show commercial viability, such as demonstrating site control, securing permits, filing an interconnection request, and “other similar, objective, reasonable criteria” that are not “unreasonably difficult.”

This could be a serious impediment to project development. It is normally economically imprudent for a developer to incur significant costs before closing on the financing and, in many instances, nearly impossible to obtain financing without a signed power contract.

One-Mile Rule

With limited exception, a renewable QF can be no larger than 80 megawatts in size, and smaller projects benefit from additional regulatory benefits.

A QF's capacity is measured in the aggregate by combining renewable generating equipment such as geothermal turbines or solar arrays with any affiliated generation that uses the same fuel source located at the same “site.” Congress authorized FERC to determine what constitutes a “site.”

Existing FERC precedent establishes a bright-line “one-mile” rule. Assets within one mile of each other are treated as on the same site.

Utilities have complained for a long time that this one-mile rule is arbitrary and allows developers to abuse the QF regulations by strategically siting components of a single large project in a manner that allows each component to have status as a separate QF.

In response, FERC is proposing to fuzz the bright-line test by establishing a “rebuttable presumption” that QFs located between one and 10 miles apart are separate facilities.

Factors that might be considered in establishing whether assets should be aggregated include shared infrastructure, real estate ownership and access rights, interconnection agreements and shared interconnection facilities and whether the assets are owned by affiliated companies or controlled, operated or maintained by the same person, share financing, were placed in service or obtained offtake agreements within a year of each other, and whether the projects share engineering or procurement contracts. FERC wants comment on what additional factors should be considered.

As proposed, the change would only apply to new projects and any existing projects that have to recertify as QFs.

This last point is critical, because the obligation to recertify is triggered by changes in upstream ownership, as well as various other changes. If this rule is adopted, then QFs that depend upon the one-mile rule will need to think strategically before undertaking any changes that could require recertification.

Power contracts signed under duress of PURPA usually require the project to maintain QF status.

The rule change might also affect distributed generation developers that rely upon the one-mile rule to claim they are exempted from QF filing requirements. This is a common practice in the rooftop solar market.

A project cannot be a QF unless and until it self-certifies or applies for authorization from FERC if it is greater than one megawatt in size. The one megawatt is measured by aggregating with affiliated facilities at the same site. While it was relatively easy for companies to determine the total capacity of distributed generation projects located within one mile, the 10-mile radius will be more challenging (and, therefore, more challenging to prove regulatory compliance to potential portfolio lenders).

FERC has authority to determine what is a “site” under the plain language of the statute. Of all the new proposals, this one probably has the highest chance of being implemented.

Challenging QF Status

There are two ways currently to become a QF. One is by making a formal FERC application. The other is by self-certifying.

A self-certification is effective upon filing.

Anyone who wants to challenge a self-certification must file a request for a declaratory order and pay a filing fee (currently \$28,990).

Historically, this has meant that only very interested parties challenge QF self-certifications, such as the utility subject to the duty to sign a power contract.

FERC is proposing to make challenges easier by allowing protests (without payment of filing fees) to be submitted by any interested person within 30 days after a self-certification. Protesters would be required to cite a specific regulatory provision that the QF fails to satisfy. FERC would issue an order within 90 days after the protest is filed, subject to a possible extension of up to another 60 days.

The QF status would still be effective upon filing, but easing the burden to challenge the filing creates greater risk that the QF status will be revoked. If adopted, lenders will probably want to see QF self-certifications filed at least 180 days before energization to accommodate this new review period.

What Next?

The proposals were issued by FERC in a 2-to-1 vote, with the lone Democrat saying in dissent that the proposed changes would “gut” PURPA. PURPA is a federal statute, */ continued page 6*

but no later than when they are reported on audited financial statements or other financial statements filed with the US Securities and Exchange Commission, other government agencies or regulators or industry self-regulatory bodies.

The proposed regulations implement sections 451(b) and (c) of the US tax code as those sections were amended in late 2017.

The specified-goods exception appears to have been adopted at the request of Boeing and other aerospace manufacturers.

The IRS is collecting comments through November 8.

The IRS disappointed companies by not allowing the future projected costs to produce prepaid goods to be subtracted as an offset in cases where advance payments must be reported as income at inception, but said it is still considering limited exceptions for companies that use the percentage-of-completion method for calculating book income. In such cases, costs could be accelerated as an offset against the amount that must be reported as income.

The 2017 tax law requires companies to report income to the US tax authorities no later than they report it on financial statements. This applies solely to companies that use accrual accounting.

The proposed regulations say there was no intention to apply a book label to a transaction where the transaction is characterized differently for tax purposes. For example, a transaction that is a lease for tax purposes and an installment sale for book purposes does not turn into a sale for tax purposes. Income would continue to be reported for tax purposes as a lease.

Also, just because income reporting is accelerated for book purposes does not accelerate it for tax if there has not yet been a “realization event” to trigger a tax. An example of a realization event is when an investment is sold. */ continued page 7*

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and FERC only has authority to implement the statute as directed by Congress.

The plain language of PURPA directs FERC to issue rules “necessary to encourage cogeneration and small power production.” Given that one of the three FERC commissioners has already determined the new proposals are contrary to this directive, any final rules can be expected to be challenged in rehearing and on appeal to federal courts.

Congress may be incentivized by the attention to revise PURPA. It may be months to years before the final outcome and industry impact is known. Even if none of the proposals is ultimately adopted, FERC has created regulatory uncertainty that will have an immediate effect on project development and financing.

We expect that any rule changes will honor existing PURPA contracts for the duration of their terms, but their individual provisions will need to be examined closely. Some QF PPAs include the ability of utility buyers to terminate the contract in the event of a regulatory change to the purchase obligation or if the seller is no longer a QF. ☺

California Moves Forward

by Jim Berger, in Los Angeles

The amended plan of reorganization that PG&E Corporation and its subsidiary utility, the Pacific Gas and Electric Company, filed with the bankruptcy court in late September would leave in place all of the renewable energy power purchase agreements and community choice aggregation servicing agreements that the utility has currently.

Financiers are taking a wait-and-see approach before financing or refinancing any project with a PG&E contract.

The plan shows that PG&E expects to pay most creditors in full.

The main battle will be with wildfire victims. PG&E cannot emerge from bankruptcy until all wildfire-related lawsuits have been settled.

After submitting its original plan, PG&E settled with insurance companies and agreed to pay \$11 billion in connection with fires in 2017 and with the Camp Fire in 2018. Ultimately, the amended plan is likely to be contingent on how the remaining unsettled wildfire claims are resolved. Additional plan amendments will be needed if PG&E settles the claims for more than what is currently budgeted.

Path Forward

The steps to obtain approval of the amended plan are as follows.

First, PG&E needs to obtain approval for the form of disclosure statement, which summarizes the plan, and for the proposed voting procedures. As of now, only the wildfire claimants would be entitled to vote because creditors that are paid in full are not entitled to vote.

Next, voting occurs. After voting, claimants can file objections to the plan. If PG&E obtains the votes needed to approve the plan, then there is a plan confirmation hearing. Finally, the plan becomes effective, once all of the conditions occur. The conditions include California Public Utility Commission (CPUC) approval and necessary financing being put into place. The CPUC must approve participation by PG&E in a new wildfire fund described below and find that the plan is consistent with the state’s climate goals and is neutral, on average, to the ratepayers.

PG&E must emerge from bankruptcy by June 30, 2020 in order to participate in the new wildfire fund.

PG&E must put in place new equity offerings and new debt at both the parent and utility level. If California enacts new legislation that provides for wildfire recovery bonds, then the utility expects to take advantage of those. However, the state legislature failed to act before the end of the legislative session in mid-September.

While the plan will change in some respects, PG&E is not currently seeking (and seems unlikely to seek) to terminate any power purchase agreements.

If ultimately approved and effective, the plan is likely to have two major effects.

First, by assuming all power purchase agreements, PG&E will avoid any drawn-out fight with existing power suppliers. The dispute earlier in the year with the Federal Energy Regulatory Commission over whether FERC must approve any cancellations of power purchase agreements becomes irrelevant if the current PG&E plan is confirmed.

Second, it strongly increases the likelihood that future projects in California can be financed, perhaps with a “PG&E risk premium” for projects with PG&E contracts. Had PG&E terminated some of its power purchase agreements, it almost certainly would have created a huge hurdle to financing any projects in California. Financiers would have paused, and possibly decided not to fund, future projects with other utilities that had any chance of being pushed into bankruptcy by their own wildfires. With two bankruptcies in 20 years, it is hard to imagine any future project with PG&E being financed.

While most utilities are currently ahead of their targets under the state renewable portfolio standard, the state will need increasing volumes of renewable energy as the RPS targets increase over time. (For the current California RPS targets, see “California Update” in the August 2018 *NewsWire*.) The assumption of all power purchase agreements ensures access to the significant capital that will be required for the state to pursue its goals.

PG&E’s proposed plan will also have an impact on existing financings.

Most financings of projects that supply power to PG&E are technically in default due to the PG&E bankruptcy. Most lenders have allowed their borrowers to remain in default without exercising remedies because it was unclear what would happen to power purchase agreements, and lenders did not want to exercise remedies prematurely. Once PG&E emerges from bankruptcy, the defaults are probably not automatically cured, but the lenders are likely to waive any / *continued page 8*

A mismatch in the proposed regulations may play a role in how some contracts should be written in the future.

The IRS proposes to treat contingent income — for example, where the amount is contingent on a future event — and contingent liabilities differently. Contingent income does not have to be reported for tax purposes, even if the book income has been reported, while contingent liabilities cannot be used immediately as an offset. For example, if an electricity supplier offers a volume discount, the discount may be a contingent liability since the supplier might have to give money back. The contingent liability is ignored. Therefore, it may be better from a tax standpoint to write the contract to charge the discounted price from the start with an add-on in case too little electricity is delivered to qualify for the discount.

The mismatch may also play a role in the drafting of project sale agreements.

Proposed regulations normally do not apply until they are republished in final form. However, companies have the option not to wait in this case as long as they do not cherry pick among the new proposed rules.

NO SALE OCCURS if the seller must pay the buyer to take a product, a US appeals court said.

The decision is important because some federal tax credits require a sale to a third party before the tax credit can be claimed. Examples are production tax credits for generating electricity from renewable energy or for making refined coal and some tax credits for producing alternative fuels.

Alternative Carbon Resources claimed \$19.8 million in federal tax credits in 2011 for making an “alternative fuel mixture.” It collected liquid residue from ethanol makers and paid a trucking company to transport it to owners of anaerobic digesters and to splash in a little diesel fuel before / *continued page 9*

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defaults relating to the bankruptcy because the plan keeps all contracts in place.

PG&E probably owes money to many counterparties (such as for energy delivered under power purchase agreements shortly before the bankruptcy filing) that it was not allowed to pay due to the bankruptcy filing. Assuming that the counterparties filed a notice of claim, these outstanding amounts will get paid as part of the resolution of the bankruptcy.

Not all parties to the bankruptcy case support PG&E's proposed plan. The official committee of tort claimants and an ad hoc group of senior noteholders have joined forces in opposition to the plan, and they are seeking permission from the court to file their own proposed plan of reorganization for PG&E. A court hearing is scheduled for October 8 to consider this request, but either way, renewable projects remain in good stead. The terms of the committee and ad hoc group's plan, like PG&E's plan, provides that no renewable energy power purchase agreement will be rejected by PG&E.

Wildfire Proposals

While the state legislature did not block PG&E from filing for bankruptcy, it has been busy trying to ensure that the other California utilities do not face the same fate and to put PG&E in a position to weather future wildfires. However, there was no serious consideration given to changing the doctrine of inverse condemnation that holds utilities strictly liable for the fire damage, even if they followed best practices to avoid fires.

In July, Governor Gavin Newsom signed a bill called AB 1054 that addresses wildfires in several different ways.

The most prominent provision is creation of a new wildfire fund to be funded by the utilities and ratepayers. Both Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) already funded their shares of an initial \$2.7 billion contribution to the wildfire fund. PG&E is supposed to contribute \$4.8 billion after it emerges from bankruptcy. PG&E must annually contribute an additional \$193 million, while the three investor-owned utilities (IOUs) combined must contribute \$300 million every year.

Neither the initial contribution nor the annual contribution is recoverable from ratepayers. The legislature wanted the utility shareholders to bear this burden. However, if a utility must draw on the fund to pay claims and then replenish the fund, the contribution to replenish is potentially recoverable from ratepayers.

The new wildfire fund will act as a general fund on which any participating utility can draw to pay future eligible wildfire claims. A utility can only make a claim on the fund for claims that exceed \$1 billion in the aggregate (or, if greater, the amount of insurance coverage required to be in place, based on a "reasonableness" standard).

If a utility receives payments from the wildfire fund, then it must file an application with the CPUC to recover costs. The CPUC is required to allow cost recovery if the costs are just and reasonable, which is determined by looking at the conduct of the utility related to the ignition of the wildfire and determining whether the utility's actions were consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances. If the utility has a valid safety certification (the standards are in the new law), then there is a rebuttable presumption that its conduct in connection with a wildfire will be assumed to have been reasonable.

The law also requires significant new spending on wildfire prevention, including \$5 billion in fire-risk mitigation spending that cannot be included in rate base.

The law also ties executive compensation directly to safety. In order to receive a safety certification, a utility must establish an executive compensation structure that is designed to "promote safety as a priority," which may include tying all incentive compensation to

Financiers are still taking a wait-and-see approach before refinancing any project with a PG&E contract.

safety performance and denying all incentive compensation if the utility causes a catastrophic wildfire that results in any deaths.

The wildfire law appears to have provided some relief to the utilities.

The rating agencies upgraded the outlook for both SCE and SDG&E and kept their ratings as investment grade. Lenders are considering funding projects with power purchase agreements with utilities other than PG&E. They are being cautious now, but the market seems to be assuming that California utilities will be safe counterparties going forward.

California's wildfire season has already started this year. Whether AB 1054 actually helps the utilities in the long run will depend on, among other factors, the severity of future wildfire losses and whether they deplete the new wildfire fund.

Another bill, SB 520, has been sent to the governor for his signature. It allows the CPUC to decide what load-serving entity should serve as the electricity provider of last resort if a community choice aggregator (CCA) were to fail.

Current law assumes that the local investor-owned utility has an obligation to serve as the provider of last resort. Under SB 520, that remains true, unless otherwise provided in a service territory boundary agreement approved by the CPUC or the CPUC designates a load-serving entity other than the local utility pursuant to a joint application by the local utility and another electricity supplier.

The bill is supposed to provide a safety net for customers of CCAs and other electricity suppliers whose suppliers exit the market.

CCAs lobbied against the bill on grounds that it entrenches the utilities as the providers of last resort; if the utility does not sign a service territory boundary agreement or a joint application, then it will remain the provider of last resort.

The bill will not slow the creation of CCAs in California or the flight of customer load to the CCAs. However, it may be a source of leverage for utilities that could be used to the disadvantage of CCAs. For example, a utility may refuse to enter the agreement or application necessary for a CCA to be the provider of last resort, unless the CCA gives the utility something in return.

Capacity Solicitation

The CPUC has found that there is a significant possibility of a resource adequacy reliability shortfall in Southern California by the summer of 2021.

To address this, the CPUC issued a */ continued page 10*

delivery. The court said it is not a "sale" to pay someone to take a product. At least two of the anaerobic digester owners paid a flat annual fee of \$950 for the product that was offset by a \$950 "administrative fee" paid back. The court said this arrangement lacked substance.

The US government rewarded anyone producing an "alternative fuel mixture" at the time with a refundable tax credit of 50¢ a gallon. An "alternative fuel mixture" is a mix of one of seven alternative fuels with a more traditional fuel, like diesel fuel. The IRS said in Notice 2006-92 that the traditional fuel can make up as little as 0.1% of the mixture by volume. One of the permitted alternative fuels is liquid derived from biomass. Ethanol is made from corn, which is a type of biomass.

The mixture then had to be sold by the taxpayer producing it to a third party for use as fuel or used by the taxpayer itself as fuel. The tax credit is in section 6426(e) of the US tax code. It expired at the end of 2017, but could be extended by Congress later this year as part of a tax extenders bill.

The process of distilling ethanol leaves water and a form of corn mash called "stillage" as byproducts. The stillage is run through a centrifuge, like the spin cycle in a washing machine, to wring out the liquid. Alternative Carbon paid ethanol producers for the liquid and paid a trucking company to transport it and splash in a small amount of diesel fuel.

The trucking company delivered the mixture to digester operators who were paid a "disposal fee" to take it with the disposal fee amount tied to how much they accepted. For example, the Des Moines Wastewater Reclamation Authority (WRA) was paid 2.634¢ a gallon. Amana Farms, another digester operator, was paid \$25 a ton. Both WRA and Amana Farms paid an annual fee to Alternative Carbon. In 2011, Alternative Carbon received \$8,950 in total fees compared to almost \$1.7 million that it paid the digester operators in */ continued page 11*

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proposed decision recently that calls for 2,500 megawatts of incremental system resource adequacy and renewable integration resources to be acquired by all load-serving entities serving load within SCE's transmission access area. The decision calls for 60% of this amount to be on line by August 1, 2021, 80% by August 1, 2022 and 100% by August 1, 2023.

SCE is required to procure 1,745 megawatts, a group of electric service providers are required to procure a total of 355 megawatts and six community choice aggregators are required to procure between five and 357 megawatts each.

Southern California needs another 2,500 MW of resource adequacy capacity over the period 2021 to 2023.

The solicitation is for all resources, as long as they are incremental to the 2022 baseline set of resources. This may give pause to those who want to develop renewable energy projects or storage facilities. However, the CPUC has made it clear that SCE must "conduct its solicitation in a non-discriminatory manner, treating all resources on a level playing field as long as they deliver equivalent value." The proposed decision also noted that "resources with different costs may be evaluated differently, so long as similar attributes are valued similarly."

Developers should be sure to show the value of their projects clearly and how the projects compare to other resources and to highlight the advantages of their projects. A new project that on

its face seems more expensive or uncompetitive may still be viable if the developer can show the project's value and how it is better than other resources to address reliability. For example, a storage project could address an important issue that the CPUC identified in its proposed decision, which is that the system "peak is moving later in the day and later in the year, which does not coincide with the value provided by solar resources."

The proposed decision does not set a megawatt requirement for hybrid generation and storage projects, but the CPUC expects such projects to be competitive in the solicitation. Another advantage for clean energy solutions is that the impacts of localized air pollutants and greenhouse gases on disadvantaged communities must be minimized.

Contracts entered by IOUs and CCAs for new resources to deliver system resource adequacy and renewable integration capacity must be at least 10 years in length. This is to avoid a cliff when resources drop off, but it could also encourage development of new projects. While traditional PPAs were for 20-plus years, many projects are now financed on the basis of a shorter revenue contract. However, developers should be mindful of the impact on financing that shorter contracts can have, such

as an increased focus on refinancing risk and lower leverage.

Another issue that developers may contend with is utility ownership. The proposed decision allows SCE to propose to own a portion of the resources to be procured, but SCE "must propose its evaluation and comparison metrics for the CPUC consideration" and "must adhere to the existing rules about utility participation in utility-run solicitations." Because the CPUC does not have authority over the ownership decisions of the non-IOUs, such entities "may conduct procurement in the interests of their own ratepayers." ☉

Scrutiny for Inbound US Investments

by Amanda Rosenberg, in Los Angeles

Acquisitions of non-controlling interests in certain power projects by foreign investors are now subject to review by the Committee on Foreign Investment in the United States or CFIUS.

Filings are voluntary in some cases, but mandatory in others.

CFIUS also has the right for the first time to force foreign companies acquiring or leasing US land to sell in cases where there are national security concerns.

The US Treasury filled in more detail in proposed regulations in September. It is collecting comments through October 17.

CFIUS is an interagency committee of 16 federal agencies that reviews foreign acquisitions of US companies for national security issues.

Acquisitions of non-controlling interests were not subject to review in the past.

However, new legislation enacted in the summer 2018 called the Foreign Investment Risk Review Modernization Act (FIRRMA) extended the committee's reach and made filings mandatory for certain acquisitions.

Many significant changes in FIRRMA to the CFIUS process did not become effective upon enactment, but have been awaiting issuance of regulations. They will still not take effect until the regulations are reissued in final form.

In the past, a foreigner acquiring a US company could voluntarily notify CFIUS. The risk if it failed to make a filing is that CFIUS could require the acquired company be divested. The US government has ordered five divestitures since CFIUS was formed in 1975, with four of out the five occurring in the last seven years, but from 2008 to 2015, roughly 35% of acquisitions that CFIUS reviewed moved into an investigation phase and 7% of proposed deals were withdrawn. (For more data on CFIUS reviews, see "CFIUS" in the October 2017 *NewsWire*.)

Non-Controlling Interests

FIRRMA expanded CFIUS authority to include the review of "covered investments" in companies dealing with critical technologies, critical infrastructure and sensitive personal data. The proposed regulations provide guidance on the scope of this new authority.

A covered investment is one in which / continued page 12

disposal fees. It earned approximately \$19.8 million that year in tax credits.

Alternative Carbon had limited advice from an outside tax lawyer. It sent him the proposed agreement with the WRA by email the same day it signed the agreement and asked him whether the proposed arrangement would qualify as a "sale." He replied that Alternative Carbon would have "a better case if you charge the user of the mixture for the fuel value, and they charge you a disposal fee."

The IRS began asking questions soon after. It sent Alternative Carbon a request for information. The company asked the outside tax counsel for help with its response. He asked which tax credit the company was trying to claim.

An internal IRS memo in July 2011 indicated the IRS was troubled by some claims for alternative fuel mixture credits involving taxpayers who sprayed small amounts of atomized diesel fuel into methane produced by anaerobic digestion of cow and hog manure when feeding the methane into generators to make electricity. The government said a fuel mixture rewarded by the tax credit required producing a single fuel and what Congress had in mind when it allowed tax credits to be claimed on alternative fuel mixtures built around "liquid derived from biomass" is that the liquid would be converted into something equivalent to compressed natural gas. The IRS memo is Chief Counsel Advice 201133010.

The IRS began a formal audit of Alternative Carbon in March 2012 and disallowed the tax credits the company claimed on multiple grounds.

It said the mixture was not sold to a third party, and the mixture was not used by the third party "as a fuel" since it was just dumped into anaerobic digesters along with other waste material.

The US claims court agreed and imposed a penalty. Alternative Carbon appealed.

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the investor does not gain control over a US business, but that gives the foreign person access to material nonpublic technical information, membership or observer rights on the board of directors or any involvement in the substantive decision-making of a covered US business.

Covered US businesses include businesses that perform certain functions with respect to types of critical infrastructure listed in an appendix to the proposed regulations. There are 28 categories of critical infrastructure listed. They include businesses that “own or operate any system, including facilities, for the generation, transmission, distribution or storage of electric energy comprising the bulk-power system” as that term is defined in the Federal Power Act.

Mandatory filings will be required with CFIUS for some new US investments by foreign investors that are owned partly by foreign governments.

The Federal Power Act defines the bulk-power system to include “facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] . . . electric energy from generation facilities needed to maintain transmission system reliability.”

It does not include facilities used for local distribution of electricity.

Thus, the acquisition of non-controlling interests in projects that are critical to the operation of the transmission grid, either due to their size or location or the provision of ancillary services, is now subject to review by CFIUS.

There is no size threshold that will cause a project to be part of the bulk-power system. A determination will need to be made based on all of the facts and circumstances. This is similar to the analysis of whether a power project is critical infrastructure

under the pre-FIRRMA framework where whether a project involved critical infrastructure was based on similar factors.

Also covered are the ownership or operation of batteries and other energy storage facilities that are physically connected to the bulk-power system and any project that provides power generation, transmission, distribution or storage directly to or is located on a military installation. A business that owns or operates LNG terminals or oil and natural gas pipelines also is considered a covered business.

A company will be also considered a covered business if it produces, designs, tests, manufactures, fabricates or develops a critical technology.

Critical technologies generally are those subject to US export controls. The US Treasury chose to leave in place a pilot program it initiated last fall that requires mandatory filings

for non-controlling investments in US businesses that operate in 27 specified industries. Covered industries include nuclear power projects and the manufacturing of transformers, turbines and batteries.

There are a number of different types of sensitive personal data the maintenance or collection of which could cause a company to be a covered business, including financial, biometric and health information.

Potential White List

Congress directed the Treasury to come up with criteria to limit the expanded CFIUS jurisdiction to certain types of investors.

There is no “black list” of countries that raise national security concerns. However, the proposed regulations suggest that Treasury plans to issue a “white list” of countries whose companies and citizens would not be subject to the expanded CFIUS review of non-controlling interests.

Whether a foreign investor is an excepted investor will depend on several factors including its place of business, ownership, prior compliance with CFIUS and sanction laws and association with a white-listed country. Criteria for evaluating whether a country should be listed on the white list include whether the foreign country has a robust foreign investment review process and

coordinates with the United States on investment security issues. An excepted investor is required to continue to meet the criteria for three years after the transaction closes.

No countries are named to the white list under the proposed regulations, and it may be some time before CFIUS releases the list. The CFIUS chairperson and at least two-thirds of CFIUS must approve of the designation.

Being an excepted investor does not limit general CFIUS authority to review a transaction in which the investor gains control of the US business. The exception avoids review only of non-controlling interests.

Mandatory Filings

FIRRMA requires mandatory filings for certain transactions in which a foreign company acquires a 25% direct or indirect voting interest in a covered US business.

The foreign company must be owned partly by a foreign government before the mandatory filing requirement comes into play.

A foreign government must have at least a 49% direct or indirect voting interest in the foreign company. If the foreign company is a partnership, then the foreign government must have at least a 49% interest in the general partner or be itself a limited partner and hold at least 49% of the voting rights of the limited partners.

Where a mandatory filing is required, the filing must be made at least 30 days before the deal closes. The filing required is a short-form declaration rather than a full notice.

Acquisitions of covered US businesses by foreign companies acquiring at least a 25% interest that are themselves owned at least 49% by a foreign government — plus acquisitions of some types of critical technologies — are the only types of transactions subject to mandatory filings under the proposed regulations. All other filings remain voluntary. However, that could change when final regulations are issued.

Short-Form Declarations

The mandatory filing is called a declaration. Declarations are subject to a 30-day review period rather than the 45-day review period for a full notice that a foreign company might file voluntarily. Any filing is made by both the buyer and the seller in the acquisition. Parties to voluntary filings also have the option of filing a declaration rather than a full notice.

The parties may stipulate that a transaction is a “covered transaction” or a “foreign government / continued page 14

The appeals court said Alternative Carbon was paying the digester owners to dispose of the mixture and not selling it to them. It said the fixed annual payments the digester owners made to Alternative Carbon lacked substance since they were not tied to the quantity or value of the mixture and were returned as an “administrative fee.”

The appeals court went further and said the entire arrangement lacked “economic substance” because “Alternative Carbon offered no evidence it ever ‘reasonably expected’ to generate any profit apart from tax credits.” It distinguished a well-known decision by another US appeals court in a case called *Sacks v. Commissioner* in 1995 that taxpayers do not have to show their activities are profitable without the tax credit in order to claim it in cases where tax credits are intended to induce companies to undertake activities that are otherwise economic. The court said that the taxpayer in the *Sacks* case at least showed that it would be able to make money in the longer term from the business.

The court said there were no grounds to waive the penalty imposed on Alternative Carbon. Alternative Carbon would have had to show that its reliance on outside tax advice was reasonable. The court said Alternative Carbon failed to follow its lawyer’s advice and the lawyer had an incomplete understanding of what Alternative Carbon was doing.

Summing up, the court said, “Alternative Carbon’s partners should have recognized that receiving millions of dollars in tax credits for transferring feedstock from one entity to another — while mixing in a meaningless amount of diesel along the way — was too good to be true.”

The court did not reach the question whether the mixture was being used as fuel.

Advice between a company and its outside counsel is normally privileged from disclosure to the government. This case shows the limits of that privilege in / continued page 15

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control transaction,” meaning they acknowledge CFIUS jurisdiction over the transaction, to further streamline the review.

CFIUS may take one of four actions in response to a declaration: it may request that the filer file a full notice, inform the parties that CFIUS cannot complete action on the basis of the declaration and they may file a full notice, initiate a unilateral review of the transaction without waiting for a full notice, or notify the parties that CFIUS plans no further action.

While many uncontroversial deals may benefit from filing a declaration, complex and sensitive transactions will probably lead to the filing of a full notice.

Real Estate Transactions

FIRREA also expanded CFIUS authority to review certain real estate transactions.

CFIUS may review the purchase or lease of “covered real estate” by a foreign person if the transaction provides the foreign person three out of the four following rights: the right to physical access, the right to exclude others from access, the right to improve or develop the site or the right to affix structures or objects to the site.

Covered real estate includes land that is part of an airport or seaport, near certain military installations or near other sensitive US government facilities. An appendix to the proposed regulations includes a list of military and sensitive sites. Different sites have different standards for determining whether land is near enough to fall within CFIUS jurisdiction, from one mile away to within the same county or part of a US Navy off-shore range or operating area.

There are no mandatory filing requirements for real estate transactions. In other words, CFIUS has the right to unwind real estate purchases or leases that present national security issues, but filings are voluntary. ☺

Bankability of Colombian Projects

by Raquel Bierzwinzky and Javier Félix, in New York, and Carlos Campuzano, in Mexico City

Colombia is in the process of awarding 1,500 megawatts of new power purchase agreements to buy renewable power.

The form of PPA it plans to use may make the financing of projects difficult for international lenders. Given the size of Colombia’s banking sector, it is hard to believe that local lenders will have the required liquidity to provide financing for most projects.

Colombia is determined to add more wind and solar electricity. It relies currently mostly on hydropower and is well behind its Latin American peer countries in terms of other forms of renewable energy.

There are only 19.5 megawatts of wind power installed capacity and 84 megawatts of solar power installed capacity. This puts Colombia among the countries with the least wind and solar installed capacity in the region.

The Colombian government recently launched a national development plan to promote wind and solar. One of its goals is that by 2022, 8% to 10% of Colombia’s energy will be produced from renewable energy sources.

In line with this goal, the Ministry of Mines and Energy is conducting an auction to award long-term power purchase agreements. The Ministry expects to add 1,500 megawatts of renewable capacity, representing a \$1.5 billion investment, in an auction that is underway currently.

The Ministry of Mines and Energy was unsuccessful in its first attempt last February to award long-term power purchase agreements through a power auction. Other countries in the region, like Brazil, Chile, Mexico and Argentina, have successfully awarded in the last few years thousands of megawatts of long-term PPAs to private generators.

The first Colombian auction required the participation of both producers and offtakers. Only eight sale offers and 12 purchase offers were submitted, according to the Colombian government. The auction had certain technical and financial requirements that were not considered commercially attractive by several generators, and purchase offers submitted by offtakers were too low. In addition, antitrust conditions that had been

put in place to avoid undue advantage by companies that were participants in both the sell and buy sides were not met. As a result, the government declared the auction unsuccessful and no PPAs were awarded.

The Ministry of Energy and Finance has redefined auction mechanics for the second auction in an effort to make it a success.

The rules to participate and the agreements to be awarded have been modified to address many participant and lender concerns. In contrast to the first auction, the second auction only allows the participation of new renewable energy projects with nameplate capacities exceeding five megawatts. Offers made by second-auction generators must be divided into three time blocks, with a price assigned for each time block, instead of having an annual reference price. Second-auction power purchase agreements will have 15-year terms rather than 12-year terms and will be financial pay-as-bid agreements and allow sellers to purchase energy from the market to compensate for any shortfalls.

The bid guidelines for this auction are available on the websites of the ministry and its mining and energy planning unit (UPME) at www.minenergia.gov.co and www1.upme.gov.co.

Auction Process

The auction process is divided into two main stages. In the first stage, participants must register and submit technical proposals to become prequalified. In the second stage, participants may file their financial proposals.

Both foreign and local players are participating in the new auction after registering with the UPME. Potential purchasers and sellers had to submit their technical proposals in early September.

Seller requirements included the delivery of evidence relating to project capacity and interconnection feasibility. Also, prospective sellers had to submit a detailed development schedule with a commercial operations date no later than January 1, 2024. Offtakers had to submit evidence that they are authorized to participate in the wholesale energy market at least through 2038.

Participants had to post bid performance guaranties as a part of the prequalification stage. The guaranty amount is based on the maximum amount of energy that a participant intends to sell or buy on any given day. These guaranties must remain in effect for at least six months after presentation of a bidder's financial proposal. The bid guidelines do not have other substantive financial or creditworthiness / *continued page 16*

cases where the taxpayer must prove it relied on the advice to avoid a penalty.

The case also shows the danger of loose descriptions by others about what is happening.

The WRA person who signed the contract between Alternative Carbon and the WRA said the fixed annual fee that WRA paid to buy the mixture was “[a] once a year charge” that was “for [Alternative Carbon’s] tax stuff We turn around and charge them \$950 for admin fees, so it is a wash.” Alternative Carbon’s own expert testified that the mixture “has a splash of diesel fuel in it . . . so that we can generate tax credits.”

The case also shows the danger of relying on private letter rulings issued to others that an arrangement works.

Alternative Carbon pointed to two PLRs involving a similar tax credit for producing alcohol-based fuels where the IRS said the fuel mixtures were sold, even though nothing was paid for them, because each producer was “relieved from the duty associated with having to dispose of the [mixture].” The rulings are PLR 9631012 and PLR 9229038. Private letter rulings are not binding on the government except for the taxpayers who received them.

The case is *Alternative Carbon Resources, LLC v. United States*. It was heard in the US appeals court for the federal circuit. The court released its decision in late September.

A REFINED COAL TRANSACTION landed in court.

The taxpayers won.

Refined coal is raw coal that has been treated to make it less polluting when burned in a power plant or factory to make steam. There must be at least a 20% reduction in nitrogen oxide emissions and at least a 40% reduction in either sulfur dioxide or mercury emissions compared to burning raw coal.

The government offers a tax credit of \$7.173 a ton in 2019 to / *continued page 17*

Colombia

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requirements for participants.

The UPME published a list of registered participants who have submitted technical proposals. The list indicates that 53 participants successfully registered for the second auction. Of those, 27 are prospective sellers with 56 renewable energy projects. The remaining 26 are potential purchasers.

Winning bidders in the next auction in Colombia may have trouble financing projects with the proposed form of power contract.

Registered generators include Acciona, Canadian Solar, Cobra, EDF Renewables, Empresas Públicas de Medellín, Enel Green Power, Trina Solar and several other developers. Registered off-takers include Celsia, Ecopetrol, Empresas Públicas de Medellín, Enertotal and other local power marketers and distributors.

The names of prequalified purchasers were published on October 2, 2019.

Only prequalified participants may submit one or more financial proposals. The proposals are binding and may not be modified once submitted.

These proposals are based on the price per kilowatt hour in Colombian pesos at which each participant intends to sell or buy energy. Potential sellers can submit offers in any of the three available time blocks, which span from 12 am to 7 am, 7 am to 5 pm and 5 pm to 12 am. Buyer offers must indicate the maximum amount of energy that the relevant buyer wants to purchase per day and the average price per kilowatt hour in Colombian pesos.

The Gas and Energy Regulatory Commission will set maximum thresholds for the prices of energy per individual offer and in the aggregate. These thresholds will remain undisclosed until the

award process has concluded. Offers exceeding the thresholds will be discarded.

Financial proposals will be submitted on October 22, 2019. They will be validated as they are filed after running a mathematical model. The model will solve an optimization equation and match sale and purchase offers while maximizing consumer benefits during each time block. Winning participants will be selected and matched with other participants regardless of their creditworthiness. The details of the model and its

results will be published on that same date along with the names of winning participants and award details.

A second round will immediately follow the first award round to compensate for any shortfall capacity.

Agreements to cover shortfall capacity will be awarded to prequalified participants that were either only partially awarded or not awarded at all during the first round.

Agreements awarded in this round will follow the same principles as those awarded during the first round, including pay-as-bid terms.

The awards will take place on October 22, 2019 and will be followed by a period allowing participants to challenge the ministry's decision. Once this period has elapsed, the ministry will officially finalize the auction. Awarded agreements must be executed within 20 business days after conclusion of the auction. The parties to each agreement must deliver their performance guaranties before executing the agreements. The guaranties must be approved by each of the counterparties to an agreement. Sellers must also deliver a commercial operations performance guaranty based on the maximum amount of energy that a seller intends to sell.

Sellers must begin supplying energy no later than January 1, 2022, even if their projects have not reached commercial operation. Energy shortfalls may be covered by purchasing energy in the market. Projects must commence commercial operation no later than January 1, 2024 or risk forfeiting their contracts and their commercial operations performance guaranties.

Bankability

Payments under power purchase agreements will be made in Colombian pesos at the prices offered by generators during the auction process. In addition to the contract price, payments to generators will include the payment of CERES, a tariff to compensate generators for the availability of their generating assets on a firm basis.

Contract prices will be adjusted on a monthly basis to reflect variations in the Colombian producer price index. There is no indexation for exchange rate fluctuations, which will be of concern for anyone using foreign sources to finance awarded projects.

Supply and payment obligations are established on a firm basis. Hence, sellers must deliver all committed energy at the offered price, while purchasers must pay for all purchased energy, regardless of whether they consume. To validate these commitments, either party can register the power purchase agreement with the ASIC, the Colombian governmental body in charge of settlement and invoicing market transactions.

Both purchasers and sellers are required to provide a first requirement bank guaranty (aval bancario) or a stand-by letter of credit as performance guaranties. These guaranties must be for 30% of the annualized hourly committed energy, multiplied by the contract price per kilowatt hour. However, a seller may reduce the amount of its guaranty from 30% to 20% once its project reaches commercial operation.

A blank promissory note with an instruction letter must be delivered by each party to the other. This is a mechanism to facilitate collection of any unpaid amounts at termination of the agreement. A promissory note is not a liquid security, so collections still will depend on the value and availability of the issuer's assets. For financing purposes, it will be important to confirm that repayment of financed debt will take precedence over the enforcement of the promissory note, including in the event of a bankruptcy or insolvency.

A defaulting party must pay 20% of the total contract value as liquidated damages if the PPA is terminated due to default. Hence, the guaranties delivered by power purchasers for 30% of the annual contract price could fall short of what is needed. The sufficiency of purchaser guaranties, together with the blank promissory note, will be closely evaluated for financing purposes.

The PPA has standard periods to cure events of default. However, no cure period is available to the seller if it fails to supply contracted energy; the power / *continued page 18*

anyone producing refined coal and selling it to a third party. The equipment that makes the refined coal had to be in service by December 2011 to qualify for tax credits. The tax credits run for 10 years after the refined coal facility was originally placed in service.

Most refined coal facilities spray or drop chemicals on raw coal as it passes overhead on a conveyor belt that moves the coal into a boiler at a power plant.

An Arthur J. Gallagher subsidiary called AJG Coal, the Fidelity Investments management company and Schneider Electric owned refined coal facilities that were placed at several coal-fired power plants owned by Santee Cooper, a utility in South Carolina.

Santee Cooper earned 75¢ a ton from taking the product. It sold the raw coal at cost and then bought back the refined coal for 75¢ less a ton.

After a long audit, the IRS sent a final notice in June 2017 disallowing tax credits that the partners claimed on the refined coal in 2011 and 2012. The refined coal facilities were put in service as early as 2009.

The IRS said no real partnership was formed since there was no real business from which the parties intended to share profits. The operation was a consistent money loser. The IRS said Fidelity and Schneider Electric were not real partners. They were just in the transaction to “monetize” tax credits.

The US Tax Court held a nine-day trial in August 2019.

Between the trial and the audit, there were meetings between multiple refined coal producers and the IRS national office in an attempt to get the national office to draw clearer lines for IRS agents in the field. (For earlier coverage, see “Refined Coal” in the April 2018 *NewsWire* and “Refined Coal” in the April 2016 *NewsWire*.)

The Tax Court rejected the IRS view of the transaction. / *continued page 19*

Colombia

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purchaser can terminate the agreement immediately.

In case of a force majeure event or third-party actions, neither seller nor purchaser will be excused from complying with its supply or payment obligations. Given the financial nature of the power purchase agreement, the inclusion of this provision seems reasonable as sellers may remain in compliance with their supply obligations by purchasing energy in the wholesale electricity market. However, sellers must cover any difference between the contract price and market price, even if the force majeure event or third-party interference is due to an act or omission of a governmental authority.

The power purchase agreement requires the power purchaser's approval for any assignment of seller rights, including any collection rights. This could prove an obstacle to financing projects.

Lenders are allowed to take control of the seller if the seller defaults under the financing documents or the power purchase agreement. An extended cure period is usually required by lenders to allow them the ability to cure or mitigate events of default by a seller under the power purchase agreement and prevent the agreement from being terminated. These lender rights are either included in the agreement itself or in a direct agreement between the offtaker and lenders. It is not clear from this power purchase agreement whether purchasers have an obligation to enter into direct agreements with project lenders.

In case of a dispute, the alternative dispute resolution mechanisms available to the parties include direct negotiations, friendly composition and arbitration pursuant to the regulations of the Arbitration and Conciliation Centre of the Bogotá Chamber of Commerce. Friendly composition can be helpful for resolving technical disputes, but it is not a commonly accepted dispute resolution mechanism by international lenders for legal disputes, as arbitration is usually preferred. Most importantly, friendly composition is an ad hoc process that may not be enforceable in certain jurisdictions.

Neither party is protected against risk of a change in law. There is no obligation in the power purchase agreement on either party to negotiate changes to the agreement to restore balance after a change in law. This will be a concern for lenders, as it is an unquantifiable risk. ☺

Community Solar: Current Issues

Audiences at community solar conferences are growing. The organizers had to add more rows to accommodate a standing room-only crowd at the annual community solar gathering in Philadelphia in July organized by the Coalition for Community Solar Access with help from SEIA and SEPA — the Solar Energy Industries Association and Smart Electric Power Alliance. A panel of community solar developers talked about new trends in how community solar projects are structured, the different business models, where they would probe on diligence before buying community solar projects and related subjects. The following is an edited transcript.

The panelists are Zaid Ashai, CEO of Nexamp, Drew Warshaw, vice president of community solar for Clearway Energy Group, Laura Pagliarulo, senior vice president of community solar and commercial sales for Clean Choice Energy, and Tom Sweeney, president of renewable energy assets for Clean Energy Collective. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

New Trends

MR. MARTIN: Tom Sweeney, what new trends do you see in community solar in 2019?

MR. SWEENEY: Two things are happening simultaneously.

One is around consumer protection. There is a loosening of contract terms to make subscription agreements more flexible for customers. It creates some challenges from a financing perspective. The trend toward stronger consumer protections is accelerating, particularly in places like Massachusetts and New York.

The other big theme is the higher volumes of distributed generation assets connecting to distribution systems and creating challenges. This is leading to things like cluster or area studies in places like Massachusetts.

MR. MARTIN: Laura Pagliarulo, new trends.

MS. PAGLIARULO: Some new states like Maryland and New Jersey are prioritizing low-income solar. We have been really good as an industry at offering a product to creditworthy customers, and avoiding the perceptions of higher project finance, acquisition costs and the expectation of default associated with low-income solar, but the industry now needs to turn its attention

to how to make community solar work while serving low-income communities.

MR. MARTIN: Are you required to provide a certain percentage of electricity to low-income customers?

MS. PAGLIARULO: Yes.

MR. MARTIN: In all states or just a few?

MS. PAGLIARULO: It is an emerging trend. Both Maryland and New Jersey, for example, have low-income requirements.

MR. MARTIN: What is the percentage?

MS. PAGLIARULO: For New Jersey, it is 51% LMI.

MR. MARTIN: LMI stands for?

MS. PAGLIARULO: Low- and moderate-income customers.

MR. MARTIN: Is that 51% of output from all of your projects in the state? Is it tested on a portfolio or project-by-project basis?

MS. PAGLIARULO: I don't know if you want to go down this path right now [laughter], but how New Jersey works is that the state has a scoring system and has made it clear that if you want to be accepted in its very limited program, you either have to be rooftop, brownfield or LMI, essentially.

MR. MARTIN: Got it. Drew Warshaw, new trends.

MR. WARSHAW: The industry is growing quickly, but the addressable market is growing more slowly than the industry. The audience and scale of this conference versus the same conference last year are phenomenal and amazing, but the addressable market is not keeping up.

MR. MARTIN: Why is that?

MR. WARSHAW: A couple of statistics are interesting. Community solar as an industry reached the one-gigawatt scale last year. Yet it will take another three years to get to two gigawatts. The scale required to justify the number of people and level of resources and capital that are in this room is a challenge.

Think about it. You have the rooftop solar industry plateauing in New Jersey as the optimal roofs already have panels on them, making community solar the natural next step to ensure everyone has access to solar and not just people with good roofs. Add to that a Democratic legislature and a new Democratic governor coming in with ambitious renewable energy goals, and you have all the makings to scale up.

And what comes out of that? Just a 75-megawatt pilot program. Look at what other new industries have done in that state and the resources they have assembled. Look at the cannabis industry. It spent \$1.2 million last year on lobbying. The offshore wind industry spent \$1 million. The community solar industry spent \$60,000. */ continued page 20*

It said both parties took significant risks by entering into the transaction.

Santee Cooper risked using a product that might damage its boilers, affect the burn temperature for the coal and affect processes in place at its power plants to control harmful emissions.

The partners risked being left empty handed after spending money to put the refined coal facilities in place since Santee Cooper could direct the partnership at any time to turn off the chemicals and let the raw coal move untreated along the conveyors. In fact, it did this multiple times. Santee Cooper shut down refined coal production "with a frequency that frustrated" the partners, including one shutdown at the Cross power plant that lasted nine months, the court said.

Arthur J. Gallagher showed Fidelity and Schneider Electric projections at the outset that suggested an investment of \$7 million in one of the refined coal facilities at the Cross power plant would be returned before the end of the first year and generate \$140 million in tax savings over 10 years for a 197% internal rate of return.

The actual returns were significantly less. Fidelity exercised puts to resell its interests in the refined coal facilities to Gallagher in 2013 and 2014. Schneider Electric had no put, but was bought out by Gallagher in 2013.

The Tax Court said the arrangements had "economic substance." It cited a case called *Sacks v. Commissioner*, a 1995 decision by a US appeals court that concluded it makes no sense to require a pre-tax profit in cases where Congress has offered a tax incentive to do something that would otherwise be uneconomic without the tax subsidy.

The judge was impressed by the amount of time that each investor spent doing diligence and the degree to which they had remained involved during operations, receiving updates and asking questions. */ continued page 21*

Community Solar

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MR. MARTIN: So the problem is the government is not hearing enough from you.

MR. WARSHAW: The challenge for all of us is we need to get serious about investing in new market development and improving the incumbent markets.

MR. MARTIN: Zaid Ashai, new trends.

MR. ASHAI: There is a certain maturation that has happened in the financing markets with community solar. We have reached a scale where tax equity, cash equity and debt are much more comfortable with this asset class than they were several years ago.

Another new trend is around customers. We are moving as an industry to more access and less emphasis on credit checks or FICO scores and moving away from long-term contracts. This is a win for the customers.

Another trend is the big push that Laura Pagliarulo mentioned on LMI. Some of these LMI programs set laudable goals, but the way they are implemented is clunky and candidly not a functioning system for financing.

MR. MARTIN: How do you reconcile what you just said with what Drew Warshaw said? He sees a slowdown in growth. You say benefits for the customers are improving. Financing is becoming more available.

MR. ASHAI: Development by nature is lumpy. We have made some really good progress in terms of the total addressable market today. The challenge is that some of the cornerstone markets in community solar are at a standstill. Massachusetts, Minnesota and Illinois were successful, but oversubscribed, and they are waiting for future programs.

The challenge is to persuade more market participants to become members of groups like the Coalition for Community Solar Access that focus on new market development. When a cornerstone market pauses from a regulatory standpoint, it is very difficult to continue to grow unless other states are in play.

Interconnection Costs

MR. MARTIN: Tom Sweeney, you told me before this panel that another new trend is “utility non-performance on interconnection.” What did you have in mind?

MR. SWEENEY: Utilities are required by law to let independent power producers connect to the grid. The challenges are cost and timing. For example, as the volume projects has increased in

Massachusetts, we have seen really significant increases in the cost of interconnection. It is now common to be charged multi-million-dollar interconnection fees by the utility.

I favor putting all interconnection costs that are past the point of common coupling into rate base. This would give the utility the opportunity to make a return and not require the project to carry the cost of the distribution system upgrades. Representative Tom Golden in Massachusetts has a bill to do this.

MR. MARTIN: Are you getting support from utilities for that idea?

MR. SWEENEY: Some initial conversations suggest they are receptive.

MR. MARTIN: Say your name and affiliation.

MS. BOOK: Hayley Book with the Pennsylvania Public Utility Commission. It is not surprising to hear utilities are receptive to putting amounts in rate base, but how receptive have the commissions been to rating basing distribution system upgrades?

MR. SWEENEY: I don't know. We are proposing this treatment only where the upgrades are actually necessary. That is hard to manage when it is done on a project-by-project basis. For example, in Massachusetts, I am paying for upgrades as a project developer that I know duplicate in some cases upgrades that are being made to accommodate other projects. There is no oversight.

If we move toward a rate-based mechanism, we can get oversight from the Department of Public Utilities to ensure the upgrades are necessary and appropriate and at the appropriate cost.

Business Models

MR. MARTIN: Let me drill down into some details, and then we will come back to the broader picture.

SEPA said last year that community solar is largely still a premium product in many markets. On past panels, you folks said customers receive a discount compared to the retail electricity rate of about 10%. The rooftop companies offer 15%. How important is this discount to your business proposition to customers?

MR. ASHAI: I am not sure why SEPA says it is a premium product because most providers offer discounts. When we talk to customers, the first driver is savings on electricity and the second driver is going green. If you cannot offer a customer savings, it is difficult to grow in this market.

MR. WARSHAW: I agree. It is not a premium product. It is a discount product. Customers pay less for electricity without

having to have the equipment on their roofs. It is the easiest way to go green.

MS. PAGLIARULO: The environmental message is really important. There must also be a discount, and there cannot be any gotcha fees. There is no cost to terminate. There is no cost if you move, you go into the military, you die. These types of things are important for the market perception of the product.

MR. MARTIN: How many of you use outside aggregators to find your customers as opposed to having your own sales forces?

MR. SWEENEY: We do direct sales to commercial, residential and government customers. We also use what I refer to as independent sales reps that may be what you are thinking of as aggregators.

MR. MARTIN: Just for the record, we had one hand go up.

There seem to be two main community solar models: one is ownership and the other is subscription. Subscriptions are the main one. Why would one use ownership, and where is it used? In the ownership model, each customer owns a particular panel or panels as opposed to subscribing to a percentage of the output.

MR. SWEENEY: The ownership model was the original model for community solar. You were essentially selling an interest in the community solar project. It is a really complicated transaction to do. It was an effort to allow customers to claim a residential solar tax credit under section 25D of the US tax code. It made projects more difficult to finance.

MR. MARTIN: Is it still used anywhere?

MR. SWEENEY: We have not done one in probably three years. There are a lot of benefits to the subscription model. It allows customers to move in and out easily.

Shorter Contracts

MR. MARTIN: Let's drill down into contracts with subscribers. On past panels, the contract terms seemed to be on the longer side — 10 or 20 years — but developers were aspiring to bring them down in length to five or fewer years. Where is the market today?

MR. WARSHAW: All over the map is the honest answer. It is everything from a no-term, retail-style product with no credit check to a rooftop-style 20-year contract at the other end of the spectrum, and then everything in between. For example, there are 20-year contracts with cancel-anytime provisions.

MR. MARTIN: Presumably all of you face the same pressure from the financial community to move to longer terms. How are the projects with the very short terms — the retail product — getting financed? */ continued page 22*

The witnesses at trial disagreed with the seriousness of the risks that Fidelity and Schneider Electric faced, but the court said it did not have to quantify the risks beyond finding that the risks were not “de minimis or remote but instead were serious risks.” It concluded, “An investor might not run shrieking from these risks, but he would consider that he was bearing these risks as he made his investment.”

The investors were real partners and not bare purchasers of tax credits, the court said. “In this case, we do not have mere paper transactions or distant, passive investors,” but “obviously real transactions with participants substantially involved in the activity.”

The investors were not lenders. There was no “written unconditional promise to pay on demand or by a date certain a sum certain.”

Each investor had to make ongoing capital contributions to cover its share of operating costs in addition to paying to buy an interest in the refined coal facilities.

Schneider also had to pay Gallagher a “finder's fee” of 5¢ per dollar of tax credits allocated to Schneider. The partnership had to pay Gallagher ongoing royalties for use of the refined coal technology of 85¢ per dollar of tax credits (expressed in terms of the tons of refined coal that had to be sold to get to this level).

Gallagher largely bore the operating costs through adjustments to the royalties. The “actual capital and operating expenses” were subtracted from the royalties the partnership had to pay Gallagher.

If operating costs increased to more than 30¢ cents “per unit,” then the royalty amount decreased. However, the royalty could not fall below 55¢.

Fidelity had a right to exit upon various triggers. Schneider Electric did not. Gallagher ran the business, but the investors had a say in 26 “major decisions.” */ continued page 23*

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MR. ASHAI: We started three and half years ago trying to drive the market toward no term and no credit checks and the idea that there can be no red-lining in community solar.

Community solar cannot be just for wealthy households. We are getting the financiers to view our platform as the credit behind the financing. They need to feel confident that our platform will hit the milestones, will hit the revenue targets and will manage attrition of customers effectively.

They do not need to look at the customer. It was a slog. We started this three and a half years ago. We started with regional banks, then we went to multi-national infrastructure lenders, and we were able to get the community there. I think that is going to be important for the rest of the industry. We have been a bit of a leading edge compared to our peers on this, but we really think fundamentally for community solar to grow and not have bad headlines on the front page with customers, it is important to move to that model.

MS. PAGLIARULO: Customers overwhelmingly want shorter-term contracts with little or no termination fees.

But a lot of the project financiers, and all of the long-term asset owners that are in this room, still want a contract with teeth. Nexamp is in a different position with a financier who is comfortable with it, but its model is still not very common.

MR. MARTIN: Zaid, are you talking about tax equity, debt, true equity? Which?

MR. ASHAI: All three.

Addressing Laura's point, financiers that were used to residential rooftop financings took a long time to get there. Their framework for assessing risk was fundamentally different. What we found is that lenders who were not already locked into a framework for financing residential rooftop solar could get there.

We did a comparison with projects that were financed with credit checks, that were not our projects from the beginning, versus no credit checks, and there was no difference in attrition rate. We have been able to show this data to the financial markets. As these data sets grow, we hope that there will be a lot more buy-in to this.

MR. MARTIN: It sounds a little like the challenge facing the community choice aggregators in California. Their problem was that they have potentially fickle customer bases. They have to persuade lenders and tax equity investors that the revenue stream is predictable. What they ended up doing is to create a

set of shadow metrics that provide an early warning that something may be amiss. If the economics start to erode, then a cash sweep kicks in to pay down the financing. Is that how yours works?

MR. ASHAI: No, we do not do a sweep. Without getting too much into the details, we have a really nice historical data set for the past three years. We know our turnover rates. We underwrite that turnover rate, and it has been effective so far.

Economics

MR. MARTIN: Switching gears to subscription terms, is there typically a fixed price for the entire contract term or does it increase?

MR. ASHAI: It is a fixed discount.

MR. MARTIN: Against the retail rate, against a potentially moving target?

MR. ASHAI: Whatever the retail rate is.

MR. MARTIN: How large is the discount?

MR. ASHAI: It is 15% in Massachusetts.

MS. PAGLIARULO: We like to offer an indexed product. We focus on clarity in whatever we are promising customers. The base discount is 5%, and 15% is probably the high end in markets that can support that.

MR. MARTIN: Is it a fixed percentage discount that moves with the retail rate?

MS. PAGLIARULO: Yes.

MR. SWEENEY: Our product is pretty similar. You have a discount in whatever credit rate the utility is applying to the power that is produced. That is the most common. The floors have gone away in most cases. It is pretty typical to see 10% as the savings. Sometimes, you see something a little bit higher. Less than that is very difficult to make work from a customer standpoint. You have to offer enough savings to make it worthwhile to participate.

MR. MARTIN: Is there a tipping point where the discount is so large that word of mouth brings in other customers? If so, what is it?

MS. PAGLIARULO: When we structure our products, we start at 5%, but the key is the other attributes. Various factors play a role. One is the target demographic in the particular area. Another is the penetration level in that area. The greater the savings, the greater the attraction for customers and the more customers come in by word of mouth, but the customers we talk to are interested in more than just savings.

MR. WARSHAW: An interesting dynamic is developing that we

have not seen in the last four years, and that is real head-to-head competition. Our biggest competition to date has not been from people who say you are offering only a 10% discount, and Nexamp is at 15%, so I am going to go with Nexamp. Our biggest competition has been lack of knowledge and the need to educate customers about how community solar works. Shopping among different service providers will increase as the industry starts to reach scale.

Community solar projects reached 1,000 MW in operation last year, but it may take another three years to get to 2,000 MW.

MR. MARTIN: How easy is it to cancel a contract and does it vary by commercial and residential customer?

MR. WARSHAW: Yes and yes. It is usually easier for a residential customer to cancel, and less easy for a commercial customer.

I was talking to one person yesterday who works with C&I solar companies. He said the trend in that market is for shorter contract terms and cancel-anytime provisions.

Community solar offers in theory the flexibility to plug someone in and out. To realize that potential, we have to persuade the financial community to underwrite the credit of the entity that will be responsible for replacing customers who cancel. It has to see we are offering a commodity at a discount. The question is whether there will be a market for it.

Investors are getting more sophisticated. Are they getting so sophisticated as they are willing to let anchor customers taking 50% of the output cancel at any time? I don't think so, at least for not money at scale, but that day will come.

MR. MARTIN: State attorneys general are placing limits on termination fees. What are typical limits, and where have such limits been imposed?

MS. PAGLIARULO: Two states come to mind. New York has a cap of \$200. The cap was imposed by [/ continued page 24](#)

The case is called *Cross Refined Coal, LLC v. Commissioner*.

The US Tax Court issued a “bench opinion” in late August that technically cannot be relied on as precedent in any other case.

UNPAID SALES TAXES that should have been paid in the past on equipment sales follow the equipment and can become an obligation of a later owner.

New Ichiban Japanese Food, Inc. sold equipment to Kashmir Kitchen in 2013. Kashmir Kitchen resold some of the equipment to Singh Restaurant in 2015.

Soon after the first sale from Ichiban to Kashmir, the New York tax authorities concluded that Ichiban had underpaid sales and use taxes from September 2008 through February 2012. Anyone buying a business in New York is supposed to file a bulk sales notice with the state. Kashmir filed such a notice, but late. The notice is supposed to be filed at least 10 days before taking possession of the assets or making payment.

New York sent a notice to Kashmir advising it to put the entire purchase price into escrow until the state could check whether any back taxes were owed. Kashmir failed to do so. New York then sent Kashmir a demand for the full back taxes that Ichiban owed on the equipment.

Two years later, Kashmir Kitchen sold what remained of the equipment to Singh Restaurant. Singh filed a bulk transfer notice with the state on April 15, 2015. It said the sales date was April 1 and that it had put the entire purchase price into escrow.

The state sent Singh a notice in July 2015 that Singh was liable for the remaining Ichiban back liability. The back liability had been paid down by about two thirds in the intervening two years.

Under New York law, the consequence of not giving timely notice is the buyer becomes liable for any [/ continued page 25](#)

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the public service commission rather than the attorney general. This is a fungible product. The idea that you are going to hold someone to a community-solar contract for 20 years is just not realistic.

The other state is Minnesota. The attorney general was concerned about liquidated damage clauses. There was a push for greater transparency for consumers.

MR. MARTIN: An issue has cropped up in Massachusetts where the attorney general has been concerned about sales pitches to low-income people and the elderly. Update us on whether this is a problem more widely than Massachusetts.

MR. WARSHAW: A number of customers in Massachusetts felt that sales tactics by some suppliers were misleading. The last thing we want as an industry is deceptive sales practices. The industry needs to police itself or others will understandably step in.

We can't have smaller providers saying they will offer a discount for one year and then change the terms in years two and three. If we start doing this, it will sink the entire industry. We need to make certain that we are sensible, transparent and fair to customers.

FICO Scores

MR. MARTIN: Zaid Ashai, you said you are moving to more of a retail model. Do you require the customers to be creditworthy and have a certain FICO score if they are individuals?

MR. ASHAI: No.

We are confident that if we can lead the market on pricing, there is no reason for the customer to leave. This is borne out in our data.

Our customer turnover is primarily because the customer has passed away or moved. This is critical. You can reduce the discount to 5%, but then you have a much higher customer acquisition cost to replace customers who leave. The smaller discount does not bring in more revenue after acquisition costs are factored in. There is a balance. And, for us, the higher discount gives us more flexibility to do without FICO scores and long-term contracts.

MR. MARTIN: Are any the rest of you moving away from requiring that customers be creditworthy?

MR. PAGLIARULO: We would love that. It is certainly what the consumers want. FICO is not a great indicator of whether someone will pay his or her small community solar bill. There are

other types of scores that are far better indicators, like a TEC score used by utilities.

But unfortunately, that is not where we are right now. The financiers have been willing to let FICO scores drift down from 700 to 650, but they are not willing to do without any score.

MR. SWEENEY: The way to get away from FICO scores is to move to consolidated billing. All the debits are consolidated onto the utility bill. The customer makes a single payment. The utility becomes your counterparty for payment. There is no FICO underwriting issue. It becomes possible to support high volumes of low- and moderate-income subscribers because the utility has the ability to handle large payment volumes.

MR. MARTIN: You don't have a FICO issue because people generally pay their utility bills.

MS. PAGLIARULO: Correct.

Consolidated Billing

MR. SWEENEY: That is the single most important change that we have to make happen over the next couple of years. It will be the enabler of real growth.

MS. PAGLIARULO: The community solar bills are currently unbundled, and it is not a great customer experience, but consolidating billing without what the industry calls purchase of receivables or POR means that asset owners are not guaranteed to be paid. Consolidated billing without POR is less of an advantage for asset owners than having the separate billing we have now.

We can see today who is paying and who is not paying. We know how customer receivables are aging. POR is like an insurance product. It means that the utility will pay us as the asset owner before taking money itself.

MR. MARTIN: Tom Sweeney, Laura makes a good point.

MR. SWEENEY: If the utility is doing consolidated billing, then you want it to use purchase of receivables. The utility should use rate-ready or bill-ready solutions. That is a common practice today in deregulated markets like New York and Massachusetts. The utilities have to offer that.

I am going to suggest that there is a different solution which is what we run in South Carolina today. It is what National Grid proposed in New York, Rhode Island and Massachusetts. Rather than posting individual credits and debits, the utility should post the net credit to the customer. If the customer received a \$50 bill credit for the month from solar generation and it owes \$45 as its debit, then the utility should post a \$5 credit. There is no POR issue. There is no bad-debt issue. There is no question about whether the utility is being paid an appropriate amount by the

consumer. That is how it works in South Carolina.

MR. MARTIN: Zaid Ashai, as you move to the retail model and try to persuade financiers that there is a stable revenue stream, how many years are you able to show them?

MR. ASHAI: We are able to show four years of data. We took a large community solar portfolio out to market for third-party financing, and we got six really strong term sheets.

There are ways to mitigate risk using weight lists. You don't lose bill credits necessarily in certain regulatory frameworks.

Picking up on Tom and Laura's discussion, the challenge today, outside of financing, is the customer experience because, in most markets, customers are getting two bills. It is easy to tell a customer he can go green and get 15% savings on electricity, and then four months later, the customer gets two bills and there is an education process. There is a cost to us to support that. The utilities are also not very good at reconciling bills, or doing bills on time, and this has become a big pain point for the industry. It can be a messy process.

MR. MARTIN: Are you more with Laura or Tom on this? Do you want to send your own bill or do you want the utility to send a consolidated bill?

MR. ASHAI: I am skeptical about the ability of National Grid to do it right. There is a fundamental issue. Utilities do not have customers; they have ratepayers. National Grid's proposal is also to do customer acquisition, and one has to wonder how utilities are going to do customer acquisition for community solar companies operating in their service territories. I think it is a tall order for them to do consolidated billing and customer acquisition. They tell us it may take years to put in the sort of back-end systems needed to do consolidated billing that most tech companies can install within months.

MR. SWEENEY: Let's change the discussion a bit. I suspect we would all agree that having the customer receive a single electricity bill so that he can see the true cost is a good thing. The question is how to get it done. You say you don't trust the utility to do it well and I agree with that, but I want a single invoice for my customer if possible.

MR. ASHAI: I agree with you. I prefer an EDI interface with the utility billing systems.

MR. MARTIN: What is an EDI interface?

MR. ASHAI: It basically allows us to access the billing system in a secure manner and create a consolidated bill.

MR. MARTIN: So the bill would come from you rather than from the utility.

MR. ASHAI: Yes.

MS. PAGLIARULO: Like the Texas model. / *continued page 26*

outstanding sales and use taxes owed by the seller. The buyer's liability is limited to the purchase price paid or, if greater, the fair market value of the assets.

Singh's notice was five days late.

The case is a warning to anyone buying equipment to make sure any sales or use taxes were paid on past transfers of the equipment. The rules vary by state.

The case is called *In the Matter of the Petition of Singh Restaurant, Inc.* The New York tax appeals tribunal rendered a decision in August.

TEXAS does not let companies providing services — as opposed to selling goods — deduct costs when calculating income subject to state franchise taxes.

A telephone company lost an effort to reduce its state franchise taxes in a Texas appeals court in September.

MetTel pays rent to other telecom companies to lease lines that it uses to provide telephone and internet service to customers.

Texas collects annual franchise taxes from companies doing business in the state. The tax is a set percentage of a form of income called "taxable margin." A company can deduct its "costs of goods sold" when calculating its taxable margin, but it must sell goods to qualify for a such a deduction. Goods are tangible property, meaning things that "can be seen, weighed, measured, felt, or touched or that [are] perceptible to the senses in any other manner."

MetTel paid franchise taxes in 2011 through 2014 on its net income after deducting its costs to provide telephone and internet services. The state disallowed the deductions. MetTel lost in both the lower court and the appeals court. Both said MetTel is providing services rather than selling tangible property.

The appeals court released its decision in late August. The case is *Metropolitan Telecommunications* / *continued page 27*

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MR. MARTIN: Is that realistic? Doesn't the customer buy its electricity at the end of the day from the utility?

"Gentailer" Model

MR. ASHAI: There is a fundamental issue that we are all tip toeing around. It all comes down to the future of the grid. We are third-party developers. We are trying to get access to customers. Utilities look at us and exclaim, "Oh my God, we are losing our ratepayers!" What does the new energy framework look like? It has to be decentralized.

We need a "gentailer" model. We are generators and also retailers. The utilities do not share that vision, and they are not compensated on that vision. The utilities are compensated on cost to capital. If they can deploy capital, they get paid for that. We are always going to bump heads on this, whether it is interconnection and whether it is billing. There are two different visions colliding.

MR. MARTIN: Some utilities are experimenting with their own community solar programs. How do their offerings differ from what you offer?

MR. WARSHAW: There are a couple different models. The most notable one was the program that Florida Power & Light announced. The industry has not been keen on it because it does not leave room for any outside developers. It is hard to tell whether it will be a true community solar program or a green program that charges a premium price for renewable power. The most common utility program is one that offers renewable energy at a premium price.

MR. MARTIN: The Florida Power & Light program is a 1,490-megawatt program. Is that the size of the program or the capacity of a series of solar projects that the utility plans to build

to offer solar electricity to its customers?

MS. PAGLIARULO: The program.

MR. MARTIN: In what sense is it community solar?

MS. PAGLIARULO: It is great that the utilities want to develop more solar in their service territories, but there has to be competition. When we compete against each other in a state, we get to a place where the customer gets the best product and the market gets elevated as a whole. When you have only utility programs, it is not community solar as it is defined in other states.

MR. MARTIN: What is the subscription rate by the time you go to financing. Is it 100%? 95%? What does the market require? How fully subscribed does the project have to be?

MR. ASHAI: It depends on the maturity of the project. When you are in construction, the investors look for a minimum amount of revenue, and if you are in a state that has a lot non-PPA revenue like upfront incentives, it will look different. That said, investors seem to be comfortable at the start of construction if the project is 25% subscribed. Once you are in a position to operate, you need to be closer to 95% or 100%.

MR. MARTIN: So 25% to get construction debt and 95% for tax equity to fund. Let's fit in a few audience questions.

Audience Questions

MR. LORD: Jeff Lord, Clean Energy Collective. You are senior executives who are shaping this industry. If there were a genie sitting in the corner and you get one wish, what would you choose to make this industry sustainable in the future?

MR. ASHAI: I would take uniformity in the regulatory and statutory framework for a lower incentive. Less money in the system, I think.

One of our biggest challenges as an industry is sustainability. You see markets go boom and bust. One of the fundamen-

tal reasons is the incentives are seen as too big up front, and then the policymakers overcorrect. They swing the other way, and the market dies. Let's use best practices. We don't need more pilot programs. There are enough of community solar projects already deployed.

MS. LAYMON: My name is Krystal Laymon, and I am with the US Department of Energy.

Some developers are trying to do without FICO scores and long-term contracts by getting financiers to focus on their ability to replace customers who cancel.

Someone talked earlier about customer benefits beyond just the electricity price discount, especially when it comes to low- and moderate-income communities.

MS. PAGLIARULO: We are at our core environmental marketers. What we find when talking to potential customers is that the environmental attributes of the product are very important.

Beyond that, there are providers with hidden elements of their contracts. Someone mentioned the example of one price in year one and then it switches to a variable rate and high or not very transparent fees. Examples are a fee if you change your subscription size, which happens frequently, or if you use more or less electricity than expected on an annual basis. Some contracts have additional costs that are not as visible as they need to be to customers.

MR. ASHAI: Community solar should be seen as not just the product offering, but also the project. When we build in an LMI community, there is also an economic benefit to the community.

MR. GIMBERLING: Brian Gimberling with Core Development Group. I have two questions. What percentage weighting between residential and commercial subscribers is optimal for raising financing, and how much resistance are you getting from utilities to signing up their existing customers?

MR. MARTIN: You are a dead ringer for the actor, Matt McConaughey. [Laughter]

MS. SWEENEY: The answers vary by market. In Massachusetts, we still have projects where 50% of the offtake is to an anchor subscriber that is a rated commercial or government entity. The remaining subscribers could be a mix of residential or small C&I customers taking 25 kilowatts or less.

New York has had an all-residential program until recent changes in its program. Now we see the opportunity to add larger commercial and industrial customers. That market will change pretty significantly.

In South Carolina, the majority of the offtake in the big project we did there was school districts and churches because that is what was mandated. The rest was residential with 5% of the offtake going to low- and moderate-income subscribers.

MR. SEHLINGER: Nick Sehlinger, Energy Capital Partners. This is for Zaid Ashai. You have short-term offtake contracts. How do you get comfortable when building a new project that a new market entrant will not come in and undercut you on price?

MR. ASHAI: Great question. Our business model is vertically integrated. We do the development, equipment procurement, construction and asset management. / continued page 28

Holding Company v. Hegar.

Power companies face similar issues. State decisions on whether electricity is tangible personal property have varied. (See, for example, “Colorado” in the August 2014 *NewsWire*, “Electricity Is Not Tangible Property” in the August 2016 *NewsWire*, and “Power Plants and Use Taxes” in the April 2017 *NewsWire*.)

A SOLAR EQUIPMENT MANUFACTURER lost an attempt in court to spread its taxable income from equipment sales over time.

King Solarman makes mobile LED lighting platforms that are powered by solar panels. Each mobile platform is a two- or four-wheel cart with a battery pack inside, solar panel and extendable tower with LED lights. The solar panel generates electricity during the day that is stored in the battery. The lights draw on the battery at night for power. The devices are used to light parking lots, construction sites and other remote locations

The company sold and leased back 162 units in a single transaction in 2014 presumably to transfer the tax benefits to passive investors. It sold the 162 units to a “fund” that was owned 99% by the passive investors, and 1% by it, for \$7,938,000. The fund paid \$2,268,814 in cash for the 162 units and gave a note for the balance of \$5,794,740. The note required fixed monthly payments over 31 months. The fund immediately leased the units to an intermediary company that subleased them back to King Solarman.

King Solarman reported the cash payment as income in 2014, but did not report the rest of the purchase price to be paid over time under the note.

The IRS said the company should have reported the full purchase price as income in 2014, and the US Tax Court agreed in a decision released in August.

King Solarman was an accrual taxpayer rather than cash / continued page 29

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We think this model makes us better able to manage the costs and makes it very difficult for a new entrant to beat us on cost.

MR. PILON: Daryl Pilon with Standard Solar. How common are PILOT arrangements and do they end up being more burdensome than helpful?

MR. MARTIN: PILOT stands for payment in lieu of taxes. It is a negotiated property tax amount. PILOT agreements often last for 10 years.

MR. WARSHAW: There is a tradeoff. A PILOT agreement gives you certainty by locking down an expense and makes it easier to finance the project. The tradeoff is that certainty versus a situation where the local jurisdiction may be holding you hostage with a high PILOT expense. It is better for financing to lock down as many costs as possible. The fewer variable cost and revenue streams, the easier the project will be to finance.

Where to Probe

MR. MARTIN: We are down to the last question. Suppose you are in the market to buy development projects from other developers. Where do you probe for potential problems?

MR. ASHAI: It is all the typical issues: site, wetlands, PILOT issues, interconnection costs. On the customer side, we want to make sure we are in a load zone where there are enough customers and that is not over saturated with projects.

MR. WARSHAW: I would say forget the project and focus on your ability to execute. These assets are trading at extremely high valuations before they become actual community solar assets. They are just a site lease, an interconnection agreement and permits.

What makes a community solar asset are the things that the investor or the platform will bring to it — the customers and the ability to manage those customers over time. You need to be certain that you can deliver that value that justifies that purchase price.

MS. PAGLIARULO: I would say hands down, the offtake, which is your revenue stream. I would probe really deeply into how customers were signed up. Have they paid the first bill? That's huge. The racking, the panels, the wires, everything else is the same across projects. You are relying on the subscribers to pay you. I would probe into how they were sold.

MR. SWEENEY: I agree. [Laughter]. ☺

Financing Distributed Batteries and Electric Vehicle Charging Stations

Pricing for bank debt for behind-the-meter batteries has shown significant margin compression in the last 24 months, suggesting growing interest among banks in lending to the sector. Several different business models for deploying electric vehicle charging infrastructure are emerging.

A developer and two investors talked about opportunities and challenges with financing these types of assets at Infocast Storage Week Plus in San Francisco in late July. The following is an edited transcript.

The panelists are Douglas Staker, a vice president at Enel X, Dan Cary, a senior vice president at Macquarie Capital's Green Investment Group, and Peter Nulsen, a director at Generate Capital. The moderator is Deanne Barrow with Norton Rose Fulbright in Washington.

Diligence Issues

MS. BARROW: Bill Peduto, the mayor of Pittsburgh, said that we are fast approaching a time when we are no longer going to make our morning toast from energy that comes from a distant power plant. He is describing the evolution of a more decentralized energy grid. To get there, a key piece of the puzzle will be access to capital to finance distributed assets. Traditional project finance expects a fixed-price, long-term offtake contract with a credit-worthy counterparty, but this is not always available with distributed energy assets.

Let's kick off the discussion by delving into the unique aspects of financing distributed energy. Peter Nulsen, Generate Capital focuses exclusively on financing distributed rather than utility-scale assets. When you are looking at a distributed energy project, where do you probe? What are the key areas on which you focus?

MR. NULSEN: There are a lot of places we probe. The first is the revenue stream. Distributed generation usually involves a combination of a fixed revenue stream together with one or more variable revenue streams that are dependent on the performance of a fleet of assets as opposed to a single asset.

A challenging aspect is that there may be several different underlying revenue contracts of varying lengths, and the lengths do not always match the underwritten term. For example, we could be underwriting a 10-year term on an asset with a 10-year life and a 10-year customer contract, but on top of the contracted revenue stream, we may be bolting on additional uncontracted revenue streams that are not fixed in future price or future term. We have to take a view on where those prices are going and how long we think the revenue streams will be around for.

Another area we focus on is volume. Generate Capital is set up to enter markets early and de-risk investments where other investors are not. We look for sponsors who can deliver at least \$50 million of projects over the next two or three years. The sponsor does not need to be doing \$100 million or even \$10 million of volume today. We will focus on its growth trajectory. Not every small energy efficiency company is going to be able to deliver that kind of deployment growth over three years. It is really important to have a view on what growth in project deployment will look like for a given sponsor.

MS. BARROW: You mentioned uncontracted revenue streams. Do you as a lender or equity investor give credit to merchant revenue when you size the loan or investment?

MR. NULSEN: We do so on a case-by-case basis. When we underwrite a merchant revenue stream, which for folks in the audience generally means subject to fluctuations in quantity or price, we would have to take a view on how the price and quantity will vary over time. We analyze the factors that influence supply and demand and general and specific market conditions. This helps us identify overarching factors that may give us comfort that the revenue stream is going to grow or perform in a certain way.

Merchant revenue streams go against the grain of traditional project finance like you said, but that creates an opportunity for a company like Generate Capital to differentiate itself. We do not necessarily mark merchant revenue zero in a pro forma financial model just because it is uncertain. If a distributed asset has a significant revenue stream with a smart story behind it, we are open to investing in it.

There are gradations in the degree to which a revenue stream is merchant. A distributed asset that receives revenue due to demand-charge reduction can be variable due to the variability of tariffs or performance of the asset. That degree of variability, however, is less than payments for frequency regulation in PJM or energy payments in ERCOT or CAISO. Different valuation frameworks are required for each. */ continued page 30*

taxpayer. Manufacturers selling inventory are generally required to use the accrual method.

Usually someone selling property for payments over time is allowed to use the “installment sale method” and report its gain on sale over the period the installment payments are received. However, the installment method cannot be used by vendors selling inventory.

The company had more than \$12 million in sales revenue, which was too much to be able to qualify for relief as a small business.

It argued that it should be able to deduct future expenses — for example, future rent under the related leaseback — as an offset against the sales income. The court said no.

The case is *King Solarman, Inc. v. Commissioner*.

PREPAYMENT OPTIONS in loans from affiliates could cause tax problems if not exercised once it becomes economically beneficial to do so.

It is not unusual for a company investing in another country to form a blocker corporation in that country to hold the investment and to lend part of the capital needed to make the investment to the blocker corporation. This allows earnings from the investment to be “stripped” in the form of interest on the loan. The interest payments are deducted in the country where the investment is made, thereby reducing taxable income. A withholding tax may or may not be collected at the border on the interest payments, depending on whether any tax treaties apply and other factors.

Loans from related parties often give the borrower the ability to prepay the loan principal without having to pay the lender a penalty.

Tax authorities across Europe expect such prepayment options to be exercised when it is economically beneficial for the borrower to do so and, if not exercised, are likely to disallow interest deductions on the loan and possibly also not to view the loan as a real loan, according to Yanick Scheuerman, */ continued page 31*

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Distributed Battery Portfolio

MS. BARROW: So the revenue analysis is done on a case-by-case basis. Let's look at a specific case. Dan Cary, Macquarie invested in a fleet of behind-the-meter battery storage projects in Southern California Edison territory. The batteries provide 65 megawatts of capacity to SCE. They are installed at businesses where they reduce demand charges for the host customers. One fleet of batteries generates two revenue streams: one from the utility and another from the host customer. Are both payments fixed? On what other issues did Macquarie focus?

MR. CARY: You are describing what we call the Electrodes portfolio, which is our partnership with AMS — formerly known as Advanced Microgrid Solutions — for deployment of almost 100 distributed battery storage facilities in the west Los Angeles basin. Before diving into Electrodes, let me talk first about our infrastructure investor philosophy at a higher level.

Growing interest among banks in financing distributed storage is leading to significant margin compression on bank debt.

For background, Macquarie's Green Investment Group is the platform through which Macquarie Group invests its balance sheet in assets and platforms that support the transition to a low-carbon economy. Our mandate is asset creation, and we partner with developers to de-risk assets for the most optimal financing terms.

The way we normally think about distributed projects in particular is to focus on three key concepts outside of project returns.

First, we look for a contractual backbone. We are not necessarily looking for a 100%-contracted, 25-year, availability-based power purchase agreement with a US utility. In today's renewable space, investors and lenders are taking a view on their

exposure to variable pricing. We review on a case-by-case basis this exposure and the market fundamentals involved, although we like to see at least some portion of the income derived from lower-risk, recurring revenue.

Second, we focus on bankability of the contracts, most importantly, the EPC contract, the O&M contract and the customer or utility agreements. We focus on whether those contracts are, or can become, non-recourse agreements with high-credit, experienced counterparties. We also try to ensure that the key tenors and exposures of the agreements are all aligned.

Third, we focus on the dynamics of the local market. Distributed resources are typically high-value when they address a specific local problem or need. We have to believe the assets we deploy are part of a long-term solution. If the distributed energy asset is providing specific "merchant" or "variable" services, then we are conscious of the saturation point for those services as more assets are deployed in the local market.

Let me illustrate those three concepts with the Electrodes story. Starting with the contractual backbone, when we invested in Electrodes three and a half years ago, AMS had successfully won an RFP with Southern California Edison to provide resource adequacy, which is California's version of capacity. To fulfill the resource adequacy requirements, AMS went on to contract with the owners of 90 different commercial and industrial sites to provide them with six-hour, behind-the-meter battery energy storage systems that, collectively, provide a total of 65 megawatts, or 340 megawatt hours, of capacity.

SCE makes a payment for capacity, and the host customers pay a fee for the batteries, saving them money on their energy bills.

It was key that these revenue streams and the associated services were with quality counterparties and that all contract terms and tenors were aligned with the rest of the contracts. We worked with AMS on more than 3,000 unique contracts and documents across the portfolio.

In terms of the local market story, the west LA basin near Aliso Canyon suffers from significant transmission and distribution

constraints. The constraints are evident today, but even more importantly, the area is expected to need an increasing level of support over the coming decades. This was a key factor for us to see value in the systems. We did extensive research to validate the local grid story to feel confident that the portfolio would be able to support the ongoing transmission and distribution concerns in the area.

MS. BARROW: You said the batteries are installed at 90 sites. How many different customers make up those 90 sites?

MR. CARY: Around 30.

MS. BARROW: Were the 30 customers rated corporations? If they were not, how did you assess credit risk to ensure creditworthiness?

MR. CARY: Good question because it is something we are having to do more and more now with distributed resources. Many of them were not rated. We spent a lot of time on each host customer to understand each and to assess the critical nature of the site to its operations. Certain characteristics regarding the site and the business being conducted there were very important. For example, if the site is leased, the lease tenor should be aligned with the customer agreement term.

Creating Load

MS. BARROW: Doug Staker, Enel X finances behind-the-meter energy storage projects on balance sheet. When you are putting that capital to work, where do you probe on diligence?

MR. STAKER: It is a matter of learning to get comfortable being uncomfortable. We have to convince Italians to be comfortable being uncomfortable, which is not always an easy task.

One of the things we focus on is the disruption factor, especially from climate change. Hurricane Sandy changed the whole interconnection process in New York. All of a sudden, everybody wanted resilience. While that was happening, we would come out and talk to folks in California, and they would look at us and say, "Resilience in California? Are you serious? There is no value stream here." Then there were wildfires. Resilience is now important in California. I try to keep my eyes open and think about what is the disruption factor that can occur.

If I only had a dollar for every time somebody asked me, "You are basing some of your revenue streams on demand-charge savings. What if demand charges go down?" But no one can give me an example of demand charges going down. The challenge for utilities right now is with managing the demand side, and they are putting more and more rate recovery on the capacity or demand side, and less on energy. / continued page 32

a tax lawyer in the Norton Rose Fulbright office in Amsterdam.

"If an intragroup loan has a prepayment option without substantial penalties, and the borrower fails to exercise the option to refinance at a point where it would be economically beneficial to do so, the tax authorities may consider the loan no longer arm's length. This could lead to denial of interest deductions above the lower current market rate or potentially a re-characterization of the entire transaction," Scheuerman said.

WIND DATA.

The national average price of wind power purchase agreements has dropped below 2¢ a kilowatt hour, according to the latest annual "Wind Technologies Market Report" released by the US Department of Energy in late August.

The average US wind farm cost \$1.47 million an installed megawatt to build in 2018.

US wind generating capacity is expected to jump by 21% to 28% in the two years ending in 2020. Total wind capacity stood at 97,960 megawatts at the end of the Q2 2019. DOE is projecting 9,000 to 12,000 megawatts of new wind farms in the United States to be built in 2019 and 11,000 to 15,000 megawatts in 2020. Capacity additions are expected to slow after that as federal tax credits phase out.

The winning bids for a form of revenue contract called a contract for differences that were awarded to six offshore wind projects by the United Kingdom in a September auction ranged from £39.65 to £41.611 a megawatt hour in 2012 dollars, the basis on which projects were bid. These translate to £44.95 to £47.18 a megawatt hour if indexed to 2019 prices.

OTHER DATA POINTS. A Rocky Mountain Institute study in September said that 90% of the 68,000 megawatts of new gas-fired power plants currently proposed in the United States will be uneconomic / continued page 33

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Although we are starting to see more contracted revenue offerings from utilities for distributed energy resources and non-wires solutions, there is still a blend of contracted and merchant revenue streams to get comfortable with.

New York just announced a largescale offshore wind project. People ask, “What does that mean from the wholesale market perspective and the whole optimization of the delivery system?” Some people are scratching their heads over how all of that power will be integrated. That tells me that there is opportunity.

Several different business models for deploying electric vehicle charging stations are emerging.

Not many people are thinking about the value of being able to create load. We always talk about the value of creating generation to reduce load, but not the value to create load at certain times in certain markets. As we start to look at beneficial electrification, where does that drive value?

MS. BARROW: Enel X has been active in the New York distributed energy storage markets since 2012. You have more than a dozen behind-the-meter battery storage projects in New York providing services to Con Ed. Does it work the way Dan Cary described for the Electrodes project in California, where there are two revenue streams? Does Con Ed make a capacity payment and do the host customers pay for demand charge reductions?

MR. STAKER: In the last year, the options in New York have multiplied.

The classic case has been behindthemet demand – charge reduction. There has always been a nice incentive stream around that service, whether from providing demand-charge reduction for the end customer or providing demand response

for Con Ed. Those programs evolved over time and have become more lucrative.

An interesting recent development is the New York Public Service Commission’s adoption of a replacement for net metering called the “value of distributed energy resources” or VDER. We have had revenue streams from solar systems, and now solar-plus-storage systems receive approval for VDER value. We perform an analysis of whether it is more lucrative to offer a non-wires solution to the utility under a contract, to participate in the demand-response program and look for the incentives available there, or to connect solar plus storage in front of the meter and export power to the grid to get the VDER rate.

We do that analysis all the time before we sign up for a non-wires solution contract where, like Dan described for Electrodes, the project has to make a commitment to provide the utility a certain level of load reduction in exchange for contracted revenue. We look at all three of those potential business cases and decide which is the better play.

Risk Premiums

MS. BARROW: Let’s talk about the cost of capital for distributed energy resource infrastructure. Keith Martin produces a webinar in January of each year called the Cost Of Capital, where industry experts give their senses of where the market is headed for tax equity, debt and term loan B financing. Let’s compare the outlook for 2019 and see if you think the figures hold true for distributed projects. It was said that debt for plain-vanilla projects in the US is pricing at between 125 and 137.5 basis points over LIBOR in terms of the spread, and that debt service coverage ratios are 1.3 or 1.4.

Dan Cary, Electrodes raised additional project finance debt late last year. Where did it land? If you can’t speak to Electrodes specifically, give us a sense of pricing and DSCRs for distributed storage generally or another class of distributed assets.

MR. CARY: I think the thing that can give the industry real comfort, and certainly has given Macquarie comfort, is that financing for distributed energy resources more generally, and distributed energy storage in particular, has changed markedly

over the last 24 months in the right direction.

We raised external debt on a project finance basis for Electrodes twice. The first financing closed in March 2017 and the second at the end of last year. The second financing was done by a bank club made up of four traditional project finance lenders. The growth in appetite in the lender market over that period was clear and the terms of the financing reflected that. Within that relatively short period, I think lenders have become more comfortable with the industry and with the way the technology works and is paid for.

In terms of return thresholds, in general I think about this by comparing a portfolio of distributed assets to an operating solar-plus-storage microgrid that has a long-term PPA with a utility as the sole revenue stream being financed and that is fully wrapped for technology and performance risk. From a lender's perspective, the debt will be priced at the sort of levels Deanne mentioned. From the investor's perspective, the levered equity return might be at high single digits.

There is a premium for every conceptual risk that you add into this "fully-wrapped" project dynamic, and that goes for both lenders and investors. There will be a premium for construction risks if the financing or sale is occurring when notice-to-proceed with construction is issued rather than when the project is in operation. There will be a premium for technology exposure for new offerings not wrapped by a bankable technology counterparty for the whole operating term. There is typically operating software risk, especially if the project is using a tool that has not been tested or proven and is not backed by a performance guarantee. There is also a premium to account for taking on complexity with a portfolio of distributed assets. At the Green Investment Group, we work to minimize these premiums through a highly-structured set of contracts, so that the project is left with minimal risks that are added into the equity return premium for the eventual financier and owner.

MS. BARROW: One follow-up question. You moved to four lenders in the second financing from one lender in the first?

MR. CARY: Yes.

MS. BARROW: We hear that there are more lenders chasing deals than there are good projects to finance. Is that true even for distributed infrastructure projects? How difficult was it to line up those four banks?

MR. CARY: There is certainly appetite in this space, but there is some reluctance to price at competitive levels before banks or investors have done their first one. I often see momentum in markets like this, in that the second and / continued page 34

compared to new solar and wind projects equipped with storage by 2035. Gas accounts currently for 35% of US power production. If gas-fired power plants become uneconomic to operate, then this will also affect pipelines that move gas . . . Wood Mackenzie, a consultancy, said in September that 17% of new US solar projects announced this year have corporate PPAs. It said 53% of power contracts signed for solar projects last year were utility purchases outside state renewable portfolio mandates . . . The winning low bid in an auction of long-term power purchase agreements in August in Portugal was for a 150-megawatt solar project that offered to supply power for €14.76 (US\$13.42) a megawatt hour. The previous low record for solar electricity was a bid of US\$17.50 a megawatt hour for a solar project this past summer in Brazil.

— contributed by Keith Martin in Washington

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subsequent deals can be executed more easily than the first as lenders and investors get comfortable with the inherent risks involved. I think as we see more deals get done, we are going to see pricing get even more competitive as people are successful in entering the space and want to grow their books.

MS. BARROW: Peter Nulsen, Generate Capital leverages most of its capital as project equity. What kind of internal rates of return are investors expecting in this space?

MR. NULSEN: To take a step back, Generate is a permanent balance sheet investor, which means we have flexibility to do project equity, project debt, asset-backed deals, mezzanine capital and all of the above, to match what the developer or entrepreneur is looking for. In a lot of cases, we piece together different kinds of financing and investment solutions to help the entrepreneur scale up from, say, a \$5 or \$10 million investment to a large, \$100 million distributed fleet.

From a returns perspective, we look at a buildup of risks. It is hard to put a number on one. Generate was one of the first investors in distributed storage in 2014. As you can imagine, the pretax return from a distributed storage deal in 2014 is significantly lower today. It is interesting to watch the lithium-ion battery storage industry come down the bankability curve and end up where Electrodes did. Other classes of distributed energy resources, like distributed fuel cells and behind-the-meter natural gas generators, can be conceptualized in terms of a risk premium buildup just like storage.

EV Charging Models

MS. BARROW: We have talked a lot about distributed energy storage. Let's shift gears to another kind of distributed asset, which is electric vehicle charging infrastructure. Doug Staker, Enel X has a business under its umbrella called eMotorWerks. eMotorWerks installs EV charging infrastructure at residential and commercial sites. What business model does eMotorWerks use to support electric vehicle charging infrastructure buildout?

MR. STAKER: It is the same as what we do with storage and the same as what we do with solar plus storage. It is really about the value of flexibility. The ability to control and manage electric vehicle charging as a flexible resource has piqued our interest.

We have installed about 8,500 car chargers across Italy. We are going to do some large programs here in California and in the northeast because we can start to see more users of EVs

showing up. This growth will lead to challenges around managing the increased load on the grid and putting value around load flexibility.

Enel X controls about 5,000 megawatts in demand response around the world through our subsidiary EnerNOC. Demand response is managing customers' peak load, in a classic case, for maybe five cycles in a hot summer or 10 cycles in a season.

Customers have a pain threshold. At a certain point, they want to opt out of the demand response program. What is nice about charging, storage or load management through software control is that it is transparent from the customer's point of view. The more transparent it is, the more people will be willing to participate in programs that can give the grid the flexibility it is going to need.

The opt outs are not just in the peak season. We are starting to see challenges in the shoulder season, when renewable production is high and load is low, so there are ramping conditions that have not been seen before. The grid needs flexible resources to help manage load effectively and with value.

MS. BARROW: There are currently only about a million electric vehicles in the United States, but California has a goal of putting five million electric vehicles on the road by 2030 and a goal of building 250,000 electric vehicle charging stations, also by 2030. Dan Cary and Peter Nulsen, what do you perceive as the key opportunities and risks for third-party financing of EV charging infrastructure? In terms of opportunities, what business models are showing promise?

MR. CARY: Macquarie Capital is able to act throughout the company and asset lifecycle as an early-stage venture investor or, alternatively, as an infrastructure investor in a non-recourse traditional project financing. We view basically any asset that is either generating electrons or using electrons and that is dispatchable as a potential product in this space. Electric vehicle charging fits that paradigm.

Several different business models are emerging. One of the companies we have invested in provides mobile EV fast charging infrastructure via a hardware sales platform.

Another business model is "EV infrastructure as a service," which is where EV chargers are effectively rented.

A third play focuses on using the software involved in EV charging technologies to monetize the assets.

Another emerging model is to include EV charging infrastructure as part of a larger, onsite distributed infrastructure package that involves a combination of solar PV, storage,

energy efficiency and combined-heat-and-power units, among others things. It can often make sense in terms of scale of the contract structure to make the EV charging stations part of that whole package.

For a traditional third-party project financing of small systems to work, real scale is needed to aggregate enough EV charging units into a financeable portfolio. There is an opportunity for somebody to work out how to create enough volume in an area where he or she can also manage the infrastructure to generate additional income.

MR. NULSEN: We have looked at clean transport a fair amount, specifically EV chargers as well as the vehicles themselves. We formed a partnership with BYD to lease electric buses to municipalities in California. We remain bullish on the sector, specifically EV charging.

There are some fundamentals worth highlighting as we move toward a third-party-financed offering. The first issue on the revenue side is utilization. You have to take a long view on the electrification of vehicles. How do you get comfortable that, say, 200 vehicles per day will travel between LA and San Francisco? A unique analysis needs to be done to get comfortable with utilization.

It will help spread the utilization risk if a lot of EV charging stations are aggregated in a portfolio, but the flip side to that coin is cost. If you can get utilization to a somewhat predictable level, then the challenge becomes ensuring that electricity costs are manageable. This might require a special utility tariff for EV charging like we are moving toward in some parts of California. There could be an energy storage play to optimize the value stream, or even a solar-plus-storage play.

It is early days still, but we are looking at how to bring all of those elements together and are working with developers and entrepreneurs to build the right kind of third-party-financing offer. Hopefully you will read about something new in the next 12 months or so. ☺

Energy Storage in ERCOT

by Sam Porter, in Austin

Who ought to own standalone energy storage in ERCOT?

The implications for generators, transmission and distribution utilities, developers and ratepayers are big.

Since utility services within ERCOT were unbundled in 1999, resource participation has been categorized essentially as either generation or transmission.

Storage has attributes of both. Storage can enhance generation by making intermittent resources dispatchable, for example. Storage can also enhance the wires and the poles, in much the same way that line packing natural gas into an existing pipeline can increase system reliability.

Texas legislators and regulators have struggled with how to handle the multifaceted storage asset within the existing binary framework.

They are expected to weigh in on the issue in the near to medium term. There seems to be momentum behind an approach that would keep storage ownership primarily out of the hands of the transmission and distribution utilities, but utilities would be allowed to buy reliability services from independently-owned storage facilities by contract, pass the costs on to ratepayers, and potentially own small amounts of storage under limited circumstances.

Current Market Structure

Approximately 90% of Texas load is served through the ERCOT market, which set a new record for peak demand of 74,679 megawatts on August 12, 2019. More than 25% of generating capacity in ERCOT as of January 2019 came from intermittent resources: 23.4% from wind and 2.1% from solar. Judging from the current interconnection queue, ERCOT's generation mix will become even more intermittent, with 59,000 megawatts of solar accounting for 54% of the queue, 36,000 of wind accounting for 33% of the queue, 10,000 megawatts of gas representing 9% of the queue, and 4,000 megawatts of battery storage representing 4% of the queue.

Superficially, with so much intermittent generation, ERCOT would seem like a ripe market for storage.

Energy storage, and battery technology in particular, are often described as a Swiss Army knife, / continued page 36

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capable of providing a wide variety of services to the grid in a single compact package. Storage deployment is still in the early stages relative to wind and solar. The tendency among developers thus far has been to pull all the blades out of the Swiss Army knife at once, to stack as many storage revenues as possible. However, recently as global energy storage markets have gained traction and matured at least somewhat, three distinct revenue streams have come into focus: capacity, energy and ancillary services. Capacity payments tend to be predictable and therefore the easiest part of the storage revenue stack to project finance. To date, energy storage has flourished in markets with meaningful capacity payments.

ERCOT, however, is an energy-only market. There are no pure capacity payments in ERCOT. To survive in ERCOT, grid-scale energy storage systems must either buy energy low and sell energy high or provide ancillary services, which are essentially operating reserves that respond to variability in load or in generation output, often for purposes of voltage and frequency control.

To date, the energy arbitrage and ancillary services use cases have not been attractive enough for storage truly to flourish in ERCOT. Currently there are just 10 operational standalone storage projects in ERCOT with a total capacity of 101 megawatts, of which 64 megawatts are from two projects. According to ERCOT, these existing storage projects are primarily used for ancillary services.

Utility-Owned Storage

Beyond energy and ancillary services, a hypothetical third option for new grid-scale storage in ERCOT would be for transmission and distribution utilities to own storage and put the capital expenditures into rate base. To date, there has been only one transmission-level storage project owned by a utility in ERCOT — a very small facility in a very remote part of Texas.

The question of utility ownership came to the fore when AEP Texas, a utility, asked the Public Utility Commission of Texas (PUCT) for permission to own storage to address reliability issues in remote parts of its distribution system. The Texas utilities code says that storage that is intended to be used to sell energy or ancillary services is a generation asset that cannot be owned by a transmission and distribution utility. But the Texas utilities code also says that transmission

and distribution utilities may not sell electricity or participate in the market for electricity except for the purpose of buying electricity to serve their own needs.

Did AEP Texas intend to own storage to participate in power markets or support reliability?

The issue divided the power community along generator and utility lines. The utilities said the law is clear, and utilities can own storage if the goal is reliability. Generators said the law is not clear and, even assuming clarity, the impact would be altered wholesale prices. Storage developers and manufacturers mostly aligned themselves with the utilities.

The PUCT dismissed AEP Texas's application and requested legislative direction. The Texas legislature only meets every other year. During the 2019 legislative session, a bill passed both chambers and was signed into law that clarified that municipal utilities and electric cooperatives may own storage without registering as a generator. However, the question of utility ownership of storage remains unsettled.

As a result, the current state of play is that transmission and distribution utilities may not own storage in ERCOT.

Possible Paths Forward

In January 2019, before the most recent Texas state legislative session, the PUCT presented legislators with four distinct options relating to ownership of storage:

[1] prohibiting a [transmission and distribution utility's (TDU)] involvement with an energy storage device other than to provide transmission and distribution service to it; [2] allowing a TDU to contract with a power generation company for reliability service from an energy storage device; [3] limiting a TDU's ownership and operation of an energy storage device only to limited, specified circumstances such as to address a reliability issue in a sparsely populated area in its distribution system; and [4] allowing a TDU to own and operate an energy storage device in circumstances where the TDU's ownership and operation of the device would provide the lowest cost transmission and distribution service.

Option 1

With the AEP Texas request to own storage effectively paused pending legislative direction, transmission and distribution utilities are not currently allowed to own storage.

As a result, option 1 would operate as an effective extension of the status quo.

Although a number of developers see great opportunities in the ancillary services markets, deployment numbers to date suggest that for storage to see greater deployment under existing market conditions, storage should also be cost-competitive in the energy markets. This is a function of the storage owner or operator knowing when and how quickly to charge and discharge, and knowing how efficiently the storage system's technology can hold the charge.

There are many storage technologies, each with unique strengths and weaknesses. The inability to hold a charge efficiently for more than a few hours at a time limits a storage system's ability to capture the full arbitrage opportunity, as does the inability to predict accurately and respond quickly to arbitrage opportunities.

Texas summers are hot and prices tend to spike in late afternoons. August 2019 was no exception: 27 of 31 days were above 100 degrees in Austin.

August 12, 13 and 15, 2019 provide an excellent case study in how peak temperatures and peak loads alone do not predict ERCOT wholesale prices. The new ERCOT peak demand of 74,679 megawatts was set on August 12, 2019. August 13 and 15 each had slightly lower demand, at 74,428 megawatts and 74,558 megawatts, respectively. And yet, new record peak day August 12 saw only two momentary spikes, first to \$7,000 a megawatt hour at 2:25 pm and then to \$8,000 a megawatt hour at 3:00 pm. In contrast, August 13 and 15 each saw prices reaching the ERCOT maximum price of \$9,000 a megawatt hour for nearly two hours, between 3:05 and 4:45 pm on the 13th and between 3:10 and 4:55 pm on the 15th.

Why? At the time of instantaneous peak demand on the 12th, there were a relatively abundant 7,468 megawatts of wind and only 3,765 megawatts of generation outages, as compared to just 4,507 megawatts of wind and 3,282 megawatts of outages on the 13th and only 2,789 megawatts of wind compounded by 4,916 megawatts of outages on the 15th.

To reap the potential profits that energy prices promise at \$9,000 a megawatt hour, energy storage systems need either to wait patiently at the ready, efficiently holding their energy charges for the precise moment to pounce, or be able to predict wind generation and other generator outages accurately. A sponsor hoping to finance such a revenue stream would also need to convince a financier that the price surges of \$9,000 a

megawatt hour will continue to occur several years from now after presumably much more solar has been built on the ERCOT grid and is generating on-peak.

Option 2

Option 2 would allow transmission and distribution utilities to contract with storage owners for reliability services, but not own storage.

This would shift the burden of the initial capital outlay from ratepayers to storage developers. In that sense, it is a pro-competitive market option.

If this path is pursued, there are several key issues to be resolved.

One issue is whether the payments made by the utility to the storage facility in exchange for the reliability services under the contract could be capitalized and therefore passed on to the ratepayers (and, therefore, not be as pro-competition as Option 1).

Another issue is whether the storage owner would be permitted to use any storage capacity in excess of the capacity required to satisfy the reliability requirements of the utility for offers and sales of energy and ancillary services.

There is also the issue of what happens if the storage facility fails to meet the reliability requirements or impermissibly participates in energy and ancillary services markets and whether any associated administrative penalties would be the responsibility of the storage owner or the utility.

Option 3

Option 3 would allow transmission and distribution utilities to own storage only under certain narrowly specified conditions.

The PUCT's January 2019 report to the Texas state legislature provided one lone example of such a condition: sparsely populated areas in order to support grid reliability on a utility's distribution system.

There are many open questions to be resolved if this path is pursued, including just how sparse a "sparsely populated area" would have to be, whether there are any other conditions beyond just distribution system reliability that would qualify, whether there might be any circumstances under which the utility could own storage on the transmission grid and participate in energy and ancillary services markets, and whether there would be an overall cap on the number of megawatts of storage a utility could own.

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Option 4

Option 4 would allow utilities to own and operate energy storage when such ownership provides the lowest cost of transmission and distribution service.

In one sense, this can be considered a limited, specified condition and, therefore, a subset of option 3. In another sense, one could argue that providing the lowest cost of service ought to be a prerequisite to utility ownership of storage in all circumstances and, therefore, Option 3 ought to be a subset of Option 4. One could also argue that contracting for services from an independent storage owner will always be cheaper than utility ownership and, therefore, Option 4 is the functional equivalent of Option 2.

Texas is weighing four options for pricing and owning storage.

Regardless of how it is characterized relative to the other options, many of the same issues still need to be resolved, such as whether there might be any circumstances under which the utility could own storage on the transmission grid and participate in energy and ancillary services markets, and whether there would be an overall cap on the number of megawatts of storage a utility could own.

A Possible Outcome

Preserving competitive markets to keep ratepayer costs as low as possible is likely to be the guiding principle for the Texas legislature and the PUCT.

Consequently, the ultimate path forward will probably involve as little intrusion on the energy and ancillary markets

as possible, while recognizing that energy storage resources can be valuable for purposes of generation and transmission as well as overall grid reliability.

A potentially likely outcome is a combination of Options 2 through 4, which is essentially what was proposed as SB 1941 by Texas Senator Kelly Hancock during the 2019 legislative session.

SB 1941 would have allowed or permitted five things. It would have allowed transmission and distribution utilities to contract with a third-party storage facility for reliability services with payments included in the utility's rate base. It would have permitted the storage owner to use any storage capacity above the capacity required to satisfy the reliability requirements of the utility for offers and sales of energy and ancillary services. It would have allowed the utility to make the third-party storage owner responsible for any associated administrative penalties. It would have required the utility to issue a request

for proposals before entering into any reliability services contracts. Finally, it would have allowed utilities to own no more than 10 megawatts of storage with the prior approval of the PUCT if the utility issues a request for proposals and receives no offers meeting the requirements.

SB 1941 passed the Senate and then the House State Affairs Committee before time ultimately expired on the 2019 legislative session.

A bill similar to SB 1941 may be proposed during the 2021 Texas legislative session. The PUCT also might pick the matter back up in the meantime. Legislators and regulators may be hesitant until there is more data about the likely impacts such a law might have on wholesale energy prices, storage deployment, consumer rates and grid reliability.

Legislators and regulators may be waiting for ERCOT to assemble a larger data set for existing storage. Of the 10 existing operational standalone storage projects in ERCOT, the oldest was placed in service in 2013, and seven of the 10 projects representing 65 megawatts of the 101-megawatt total installed capacity became operational in 2017 or later, so the sample size is small.

As a practical matter, ERCOT does not currently have much visibility into storage resources. In essence, the grid operator can see storage as load when charging and as generation when discharging. But in order to understand the extent to which a storage facility could be a reliability resource, ERCOT must be able to model how storage will act, so ERCOT will eventually need to see state of charge and have an understanding of potential rate of charge and discharge.

Although ERCOT is entirely within the state of Texas and, therefore, not subject to federal regulatory jurisdiction, ERCOT is monitoring the changes other independent system operators are undertaking in compliance with FERC Order No. 841. Multiple ERCOT stakeholder task forces, working groups and nodal protocol revision requests continue to tackle some of the finer questions posed by grid-scale storage, such as telemetry requirements, data reporting obligations, hub-versus-node pricing when charging and discharging and responsibility for transmission charges through ERCOT's four coincident peak calculations. Meanwhile, the Texas legislature and PUCT work through the big question of storage ownership.

Even as stand-alone storage waits for the Texas legislature and the PUCT, developers are announcing pure merchant storage facilities.

Whether these projects will be built will depend on the risk tolerance of investors and lenders for the energy and ancillary services markets and whether a federal investment tax credit is forthcoming for standalone storage. In addition to standalone storage, co-locating storage with solar, primarily to capture the existing solar investment tax credit on the storage components, but potentially also to firm up hedging-related volume commitments will continue apace. And while “energy alerts” such as those issued on August 13 and 15 sound alarming, in many ways the energy-only market structure in ERCOT achieves its desired purpose: the lights did not go off and prices went up, incentivizing development.

We can expect more storage on the ERCOT grid, that much is clear, but the questions of who owns, who pays and who profits will depend in part upon the Texas legislature and the PUCT. ☺

A special thanks to Suzanne Bertin at the Texas Advanced Energy Business Alliance and Charlie Hemmeline at the Texas Solar Power Association.

ERCOT Price Spikes

by Rob Eberhardt and Christine Brozynski, in New York

The price to buy wholesale power in ERCOT — the grid that serves Texas — spiked to \$9,000 a megawatt hour at certain intervals over the course of a few days in August 2019.

While at first glance a high price might appear to be a boon for independent power companies selling power in the area, many of them instead faced challenges as a result of the price spikes, particularly those with offtake agreements that are “virtual” power purchase agreements — called VPPAs — or fixed-volume hedges.

Below is a summary of how projects with such arrangements are affected economically by price spikes like those in August.

VPPA

For projects using a VPPA as an offtake, the effect of the price spikes depends on how the VPPA was structured.

Typically a VPPA is a contract for differences with a “strike price” per megawatt hours. A contract for differences looks like a power contract in form, but electricity is not physically delivered. Instead, the power producer agrees to pay the offtaker the current market price for electricity, and the offtaker pays a fixed price back. The two payments are netted so that only a net payment is made in one direction.

To the extent the current market price of power under a VPPA exceeds the fixed “strike price” the offtaker has agreed to pay, then the independent power company must pay the excess to the offtaker for each megawatt hour of power produced by the project. To the extent the current market price of power produced by the project is lower than the fixed strike price, then for each megawatt hour of power, the offtaker must pay the difference to the independent power company, thereby providing a floor price the project will receive for its electricity.

VPPAs differ in how they calculate the floating market price.

Some VPPAs settle at a node on the power grid. Because projects sell the physical output in fact at the node for the nodal price, the merchant revenues earned by any project with such a VPPA will generally align with the floating price under the VPPA. If all goes well, then there should not be a gap between the merchant revenues and the floating amount under the VPPA. The independent power company should have enough revenue to cover its obligations under the VPPA. / continued page 40

Price Spikes

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Other VPPAs settle at the hub, which is a price point compiled by ERCOT that is representative of the liquid trading price in that area. The floating price under such VPPAs is tied to the hub price, while the merchant revenues earned from the project from selling its actual output at a grid node are tied to the nodal price. As a result, merchant revenue received by the independent power producer from the actual sale of its power will not always line up perfectly with the floating amount it must pay under the VPPA. The difference between the hub price and the nodal price is called “basis risk.”

How electricity price spikes in ERCOT affect renewable energy projects with hedges depends on how the hedges are written.

If the hub price spikes, but the nodal price spikes to a lesser degree, then the independent power company will have to come out of pocket for that difference to satisfy its obligations under the VPPA. Given that VPPAs are typically settled on a monthly or quarterly basis, the hours in which the price spiked could be mitigated by other hours during the month or quarter in which the price was lower, so the price spike will not necessarily cause an immediate liquidity concern for the project.

VPPAs are usually structured as “as-produced” contracts rather than fixed-volume contracts. As a result, if a project company fails to produce power during the price spike period, then the project company generally will not owe anything under the VPPA during that period.

Physical Fixed-Volume Hedges

Projects with fixed-volume hedges also may encounter difficulties during a price spike.

Most of the fixed-volume hedges in ERCOT are physical,

meaning the independent power company that has sold its actual electricity to the grid for a nodal price then buys back a fixed volume of power at the hub and immediately resells that hub power to the hedge counterparty.

If, during the price spike, the project happens to produce an amount of power equal to the delivery requirement under the hedge for that hour, and if the spike in the nodal price happens to be equal to the spike in the hub price, then the project should not have difficulty covering its purchase obligations under the hedge. The independent power company will not profit from the price spike, but it will not be harmed either.

However, there may be a mismatch in at least one of two respects. First, there may be a mismatch between the volume required to be delivered for that hour under the fixed-volume hedge and the volume of power produced by the project. This is called volume risk. Second, there may be a mismatch between the price at the hub and the price at the node. This is called basis risk.

In the case of volume risk, if the project produces more output than it is required to deliver under the fixed-volume hedge, then that will provide a cushion to help mitigate basis risk and may even allow the project to profit from the price spike.

However, if the project produces less output than it is required to deliver under the fixed-volume hedge, then the independent power producer must come out of pocket to purchase the electricity it must deliver under the fixed-volume hedge to the extent that merchant revenues are not enough to cover the cost.

Because the purchase must be made for that hour and purchases typically are settled on a daily basis (unlike VPPAs where the settlement is monthly or quarterly), the project company will be forced to pay the \$9,000 hub price per megawatt hour to satisfy its obligations under the fixed-volume hedge without adequate merchant revenues to fund the payment, which could cause liquidity issues. The worst-case scenario is if the project is not producing, in which case the project would have to find money to pay the entire amount under the fixed-volume hedge for that hour with no merchant revenues.

Credit Support

A separate consideration is the amount of credit support the independent power company has had to provide to the scheduling entity that handles sales of electricity from the project into ERCOT. Each project bidding into ERCOT is required under the ERCOT protocols to engage a “qualified scheduling entity” or “QSE.” The QSE interacts directly with ERCOT and manages the process of bidding into ERCOT on behalf of the independent power company.

Under the ERCOT protocols, the QSE, rather than the independent power company, is required to post credit support to ERCOT.

These credit support requirements can vary over time based on anticipated settlement obligations to ERCOT. The QSE then enters into separate arrangements with the independent power company for credit support to be provided by the project to the QSE. This credit support is negotiated between the QSE and the project, so it does not necessarily match the credit support the QSE has had to provide to ERCOT.

To the extent that the credit support amount provided by the project to the QSE is linked to the QSE’s corresponding variable collateral posting requirements to ERCOT, then the project will be doubly exposed during periods of price spike: once in terms of credit support required to be posted to the QSE, and again in terms of actual settlement payments under the hedge.

One potential mitigant for price spikes for projects with fixed-volume hedges is a tracking account. Many fixed-volume hedges have a tracking account that operates as a loan from the counterparty under the fixed-volume hedge to the independent power company for the amount of any mismatch between the amount the independent power producer had to pay to purchase the power it needs to deliver under the hedge for a given month and the merchant revenue earned by the independent power producer during that month from sales of the project electricity to the grid. An actual loan in the amount of that mismatch is made by the hedge counterparty to the project each month, but only up to an aggregate cap. The loan is repaid when the fixed amount the independent power company receives under the hedge is more than the merchant revenues during a given month.

The purpose is to offer some cushion to the project company to help with basis risk and volume mismatch. If the price spike is significant enough, then the loans made by the hedge provider might reach the aggregate cap, in which case the tracking account will not be available for further use unless it is repaid in whole or in part by the independent power producer. ☉

Depreciation Bonus Questions Answered

by Keith Martin, in Washington

New depreciation bonus regulations that the IRS issued in September answer a number of questions that have been coming up in M&A and tax equity transactions.

Some of the regulations are final. Others are merely proposed. The IRS is collecting comments on the proposals through November 23.

Background

A large tax-cut bill enacted in late 2017 allows the full cost of equipment to be written off immediately rather than depreciated over time. This is called a 100% depreciation bonus.

Such a bonus may be claimed on equipment acquired and put into service after September 27, 2017.

Equipment that straddles September 27, 2017 — it was acquired or was under a binding contract to be acquired before September 27 and is put in service after — qualifies for an immediate write off of from 50% to 30% of the cost, with the rest of the depreciation to be taken over time, depending on when the equipment is put in service. Straddle equipment qualifies for a 50% bonus if it was put in service in 2017, 40% in 2018, 30% in 2019 and 0% after that.

The 100% bonus will end in December 2022, but then phase down at the rate of 20% a year through 2026. Most assets must be in service by then to qualify for any bonus. However, assets, like transmission lines, gas pipelines, and gas- or coal-fired power plants will have an extra year to get into service, but only the tax basis built up through the deadline without the extra year will qualify for whatever bonus applies.

The 100% bonus can be claimed on both new and used equipment. However, the used equipment cannot be acquired from a related party, meaning from another company with whom the buyer has more than 50% overlapping ownership.

Regulated public utilities do not qualify for a bonus. Real estate businesses have a choice: they can choose between a 100% bonus or being able to borrow without a new limit on interest deductions.

A depreciation bonus has been available at different levels since late 2001. Most tax equity investors have been uninterested in claiming it, except in 2017 when / *continued page 42*

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Congress was expected to reduce the corporate tax rate and investors tried to accelerate deductions to take them against the high rate. Tax equity investors would rather spread their scarce tax capacity over more projects than use up tax capacity immediately as deals close.

Companies can opt out of the 100% bonus and depreciate assets over time. The bonus is automatic unless an election is filed not to take it. The election is made at the entity level and binds the entity to the same choice for all assets put in service that year in the same asset class. Thus, for example, an election can be made not to take the bonus on equipment that would otherwise be depreciated over five years, while keeping the bonus on other assets. Similarly, one partnership can choose to take the bonus while another partnership formed by the same developer can choose a different path.

Corporations that join together in filing a consolidated tax return are treated as a single company. Elections made by the parent corporation bind the entire group of corporations.

M&A Issues

The regulations answer a number of technical questions that modelers have been asking in M&A and tax equity transactions.

Many projects in the power and other infrastructure sectors are owned by limited liability companies that are treated as partnerships for US tax purposes. In addition, most tax equity raised in the renewable energy market takes the form of partnership flip transactions. (For more information, see “Partnership Flips” in the April 2017 *NewsWire*.)

When someone buys a partnership interest at a premium to the remaining “basis” the partnership has in a project, the buyer can depreciate the premium by having the partnership make a section 754 election to step up basis.

Bidders in M&A deals ask whether this step-up depreciation can be taken entirely in the year the partnership interest is purchased. The IRS said yes, in most cases.

The step-up depreciation is considered depreciation on used property if the project was already in service. A bonus can be claimed on used property, but not if the buyer owned an interest in the property earlier. The IRS will treat each partner as if the partner owns a percentage interest in the partnership assets directly. This means that a partner who has a 30% interest in a partnership that increases to 50% by buying an additional interest from another partner can claim the bonus on any step-up

depreciation on the additional 20% interest. The buying and selling partners cannot be affiliates. A partner determines its existing interest as a fraction of the total depreciation deductions it was allocated by the partnership during the current calendar year plus the five previous calendar years.

The IRS also said it does not matter if the partnership opted out of the bonus that year. A separate election would have to be made by the partnership not to claim depreciation on the step-up depreciation.

Tax Equity Issues

A tax equity partnership may be put in place in one of three ways.

The developer may be treated as contributing the whole project to a new partnership with the tax equity investor. Alternatively, the investor may be treated as having bought an undivided interest in the project from the developer, with both the developer and investor then contributing their undivided interests to the partnership. Finally, both the developer and investor may make capital contributions to a new partnership that the partnership uses to buy the project company.

If the project was already in service in the first two models — as opposed to the project-company-sale model — then depreciation on the asset must be split between the partner making the contribution and the partnership based on the number of months that each owned the asset during the year of contribution. The depreciation for the month in which the asset is contributed belongs to the partnership.

However, the depreciation bonus works differently in one situation. That situation is where one of the partners owned an interest in the project before the project is contributed to the partnership and the project is first put in service and then contributed to the partnership in the same tax year it went into service. In that situation, the IRS said the entire bonus belongs to the contributing partner and remains outside the partnership.

Another basic principle is that a company may not take any depreciation on an asset that it places in service and sells in the same year.

Putting these two principles together, suppose a tax equity investor comes into a project by paying the developer directly for an interest in the project after the project is in service. The developer would not be able to claim any depreciation on the share of the project considered sold to the investor. The investor should be entitled to a bonus even if the project was already in service. A bonus can be claimed on used property. However, any

such bonus would remain with the investor outside the partnership because one of the other partners — the developer — owned an interest in the share of the project sold to the investor in the same year. The partnership takes the asset with a zero basis and with a “built-in gain” that leads to something called section 704(c) adjustments inside the partnership. Section 704(c) adjustments are discussed below.

Two other questions people have been asking in tax equity partnership deals have to do with “section 704(c) adjustments” and “excess cash distributions.”

Buyers should be able to deduct the full premium paid in many M&A transactions for US tax purposes.

If a project has appreciated in value before the tax equity investor makes its investment, then the partnership will have to make something called “section 704(c) adjustments.” They address a fairness issue. If A and B form a 50-50 partnership with the understanding that each will contribute \$50, and A contributes an asset worth \$50 that it spent \$30 to build and B contributes \$50, then it is not a good deal for B because B will end up having to pay 50% of the tax on the \$20 “built-in gain” in the asset that A contributed some day in the future when the partnership sells the asset. Section 704(c) requires that A make it up to B by shifting depreciation to B to which A would have been entitled. This has the effect of causing A to pay tax on the built-in gain over the same period the depreciation is shifted.

Partnership agreements choose how quickly to make these adjustments. The most rapid adjustments are through use of the “remedial” method. In that case, the developer reports most of the built-in gain on a wind or solar project over five years in a manner that mirrors the 5-year MACRS schedule.

Now with a 100% depreciation bonus, is it possible that the full built-in gain would have to be reported immediately if the remedial method is chosen? The IRS said no.

Another question the IRS addressed has to do with excess cash distributions. Each partner in a partnership has a capital account and an outside basis. These are two ways to track what the partner put into the partnership and is allowed to take out. They go up and down to reflect what is happening inside the partnership. Once a partner’s outside basis hits zero, then any further cash the partner is distributed must be reported as capital gain. This makes for an inefficient deal structure since cash does not normally have to be reported as income.

Whenever there is such an excess cash distribution to one of the partners, the partnership steps up its “inside” basis in the project. This leads to more depreciation. The IRS said this additional depreciation cannot be taken as a depreciation bonus.

The regulations also address some issues in leasing transactions.

Regulated utilities are not allowed to claim a depreciation bonus on equipment used to supply electricity or services at regulated rates of return. People ask what happens if the utility sells and leases back equipment to a tax equity investor: can the lessor claim a bonus? The answer is yes. The lessor cannot be a regulated utility itself. This is still just a proposed regulation, but taxpayers may rely on the proposed regulations as long as taxpayers apply all of them rather cherry pick the parts that suit.

An example in the regulations makes clear that a lessee of equipment who exercises a purchase option can claim a 100% bonus. However, the example involves a lease rather than a sale-leaseback. The lessor bought the equipment directly from the manufacturer and then leased it to the lessee. None of the sale-leaseback examples in the regulations addresses what happens if the original transaction was the lessee bought the equipment from the manufacturer and sold and leased it back.

Finally, wind and solar companies have been racing to start construction of projects ahead of deadlines to qualify for federal tax credits. One way to start construction is to start “physical work of a significant nature” on the site or at a factory on equipment for the project. Any such work must not start before a binding contract is place for the work. People ask whether it is enough that the contract is / *continued page 44*

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binding on the developer or whether it must also be binding on the construction contractor or equipment vendor. The IRS said a contract is not considered binding for depreciation bonus purposes unless it is binding on both. ☺

Greening the Fertilizer Sector

by Andrew Hedges, in London

Fertilizer companies may become an important new market for renewable energy developers.

Ammonia production via the Haber-Bosch process is critical to the nitrogen fertilizer sector, which in turn underpins the ability to feed the current world population. Currently, the sector has an annual turnover of US\$250 billion. It is consuming 3% to 5% of global natural gas production and has a carbon footprint of 1.5% of global emissions.

Increased investment in green hydrogen can be expected to transform the production of ammonia in the 2020s due to four factors.

First, various pilot projects are now testing whether renewable energy can be used to produce ammonia without new technology advances.

Second, significant reductions in capital costs have made renewable power plants cost competitive with natural gas for the production of hydrogen.

Third, a deep pool of renewable developers is prepared to offer low-cost electricity on a long-term basis.

Fourth, there are now cost effective solutions for managing the intermittency of renewables for industrial processes requiring baseload power delivery.

There are challenges ahead, but all that is required in the near term is the right partners in the right location.

Proof of Concept

The Haber-Bosch process involves combining hydrogen and nitrogen gas over an iron catalyst, at high temperatures and pressures, to produce ammonia. Globally, almost all hydrogen is produced from fossil fuels such as gas or coal, and half of that hydrogen is used in ammonia production using the Haber-Bosch

process. Greening this process can involve both using renewable electricity as a power source and using hydrogen produced by electrolysis powered by renewable electricity.

A number of pilots have, or are planned to, show how this can occur using readily available technologies.

In July 2019, one of the world's largest fertiliser companies, Yara, announced that it is working toward making Yara carbon-neutral by 2050, including by using carbon-neutral ammonia to produce nitrate-based fertilizer. It is currently undertaking a feasibility study on the design of a green hydrogen plant integrated with Yara's existing ammonia plant in Pilbara in western Australia. The goal of the feasibility study is to convert the Pilbara ammonia plant from one that relies completely on natural gas for its hydrogen to one where a significant share of its hydrogen comes from renewable power. It will do so by using a 2.5-megawatt solar array to power a bank of electrolyzers.

Australia is also the location of the south Australian government-funded demonstration project by Hydrogen Utility. That project will comprise a 15-megawatt electrolyzer system to produce hydrogen. The plant will also include a small ammonia plant with the aim of being one of the first commercial facilities to produce ammonia from renewable energy.

In August 2018, OCP Group announced plans to develop green hydrogen and green ammonia as sustainable raw materials for use in fertilizer production. This includes building pilot plants in Germany and Morocco.

Siemens is currently running a green ammonia demonstration plant in Oxford in the United Kingdom. This project uses a wind turbine to power a typical Haber-Bosch process, including the production through electrolysis of hydrogen for that process. The demonstration plant only uses existing mature technology.

In 2018, Siemens Gamesa announced a partnership with Danish climate innovation fund Energifonden Skive to investigate the production of ammonia from wind power at an eco-industrial hub in Denmark.

It is highly likely that by the early 2020s, there will be body of demonstration plants that can the viability of producing ammonia from renewable energy at scale.

Low-Cost Renewables

Various studies regarding the production of hydrogen from electrolysis have highlighted the critical importance of the cost of energy.

For the baseload production of hydrogen for an industrial process, alkaline electrolyzers are an appropriate and mature

technology. The capital cost of these is also well understood. Most studies expect capital cost reductions to occur. However, in the near term, the key to an early roll out of green hydrogen for ammonia production will be low-cost renewable electricity.

For example, one study has shown that renewable electricity costs of 3¢ or less a kilowatt hour means a cost of US\$2 a kilogram to produce hydrogen, which is cost competitive with hydrogen produced from natural gas. There are numerous recent examples of the steep decline in the cost of solar electricity. In solar-rich locations such as Saudi Arabia, Portugal, California and Brazil, competitive procurement of new-build solar electricity has led to bids of well under 3¢ a KWh.

Intense competition is driving these results even as governments are scaling back financial support for mature technologies such as solar PV. In some countries, government subsidies are now also bid. Renewable developers will continue to bid for declining subsidies as such subsidies often provide the long-term revenue certainty necessary for debt financing. As technologies such as solar move to parity with other technologies, the search for revenue certainty for new-build projects will be a continuing dominant theme.

It is this dynamic that makes ammonia production a natural partner with renewables.

Over the last 10 years, a significant amount of renewable capacity has been developed on the basis of direct-sale arrangements between generators and corporate customers. These corporate PPAs provide an important alternative to government financial support for renewables and disappearing utility contracts.

On current trends, there is little doubt that an ammonia producer in the right geographic location would be able to

procure a long-term renewable energy solution for at-scale production of green hydrogen, with costs well below current costs of gas-based hydrogen production. The intermittent nature of the renewable energy production would need to be managed as discussed further below. An alternative approach would be for the ammonia producer to use power from the grid, but hedge that cost through a virtual PPA with a large renewable energy facility in the region. The grid charges incurred in importing power to the ammonia production facility would have to be accounted for in the overall economic model.

Managing Intermittency

Use of renewable power generation at on-site industrial facilities triggers concerns that the intermittent nature of the output makes renewable power an inappropriate solution. That is not the case when the variety of existing and emerging solutions are considered.

There are numerous examples in the US and European markets of contractual solutions whereby the on-site user of renewable power will receive a firm delivery profile on a cost-effective basis. In practice in a place like the United Kingdom, this means that power used will be a mix of on-site generation and imported green electricity, meaning electricity backed by appropriate certificates. In the United States, a contractual solution may be for the renewable generator to offer a shaped product where it uses a trading arm to supplement any shortfalls in renewable electricity with electricity from other sources.

The cost of batteries is falling quickly, and there are many global examples of developers prepared to use batteries to offer an on-site user a firm power delivery solution based on, for example, solar with batteries.

Both hydrogen and ammonia can be stored and then used for generation of electricity. While the economics of these solutions make them less likely to apply for the first wave of green fertilizer production, it is feasible to consider integrated solutions where excess renewable generation is used to produce hydrogen that can then be used at a later time to smooth electricity generation profiles. ☺

Fertilizer companies may become an important new market for renewable energy developers.

Environmental Update

As the November 2020 election nears the start of its one-year countdown, a number of significant environmental regulatory reversals being pushed by the Trump administration look likely to depend on the outcome.

The ballot box could decisively determine which direction the federal government will pivot on a slew of regulatory matters affecting industry, from autos to power generation.

If President Trump is re-elected, then his administration will presumably continue to use executive authority to push for further deregulation, which efforts will join the others already mired in litigation.

If his Democratic opponent wins in 2020, then the new administration will probably drop all or most of the pending rollbacks. To the extent possible, pending lawsuits will be withdrawn or allowed to die on the vine as the new administration begins to feel its way toward its own administrative goals in the absence of clear instructions from Congress.

Perhaps more than ever, industry is facing what it dislikes most: planning in the face of regulatory uncertainty.

Clean Cars

The Trump administration is proposing to roll back states' rights in a number of areas by asserting federal supremacy.

It moved in September to revoke California's authority to regulate tailpipe emissions from motor vehicles.

President Trump said on September 18 that the administration is finalizing replacement efficiency standards for cars after 2020.

He tweeted, "The Trump administration is revoking California's Federal Waiver on emissions in order to produce far less expensive cars for the consumer, while at the same time making the cars substantially SAFER . . . Many more cars will be produced under the new and uniform standard, meaning significantly more JOBS, JOBS, JOBS! Automakers should seize this opportunity because without this alternative to California, you will be out of business."

Tailpipe emissions are the largest source of greenhouse gas emissions in the United States at approximately 29%, which is 1% more than the utility sector.

California's current tailpipe rules — before the rollback — would require automakers to build vehicles that achieve an average fuel economy of 54.5 miles per gallon by 2025. The Trump proposal would freeze average fuel economy standards once they reach about 37 miles per gallon in 2021.

The federal government is now asserting the right to

"preempt" or override separate state standards. California officials said they will sue to block revocation of a long-standing federal waiver allowing California to adopt stricter pollution controls than the federal government.

If successful, assertion of federal preemption would have national consequences. California has 35 million of the roughly 200 million US motor vehicles, and 13 other states have adopted its tighter tailpipe greenhouse gas standards covering roughly a third of US vehicles.

The automakers are caught in the middle. Four automakers signed an agreement with California in July to comply with tighter emissions standards even if the standards are revoked.

In response, the Trump administration suggested that the agreement may violate antitrust laws, prompting the US Department of Justice to open an investigation.

The question of which standards apply to vehicles in California and 13 other states will probably be determined in the US Supreme Court after years of litigation if not withdrawn by a new administration.

Clean Power Plan

A federal appeals court dismissed as moot various legal challenges to the Obama "Clean Power Plan" in September after the Trump administration replaced it with a new "Affordable Clean Energy" plan. The Trump plan took effect on September 6.

Despite the dismissals, the litigation over the underlying issues is far from over.

Almost all major environmental rules land inevitably in court no matter in which direction they take the country. A lawsuit called *American Lung Association, et al. v. EPA, et al.* has already been filed challenging various aspects of the new Affordable Clean Energy plan. It is expected to address many of the same issues at the heart of the recently dismissed cases, but from the other direction.

The US Environmental Protection Agency asked the court to put the case on a fast track. It hopes for oral arguments in April in the hope of obtaining a trial court decision before the end of President Trump's first term.

A central issue in the case is whether EPA has authority to issue greenhouse gas standards based on actions taken "beyond the fence line" of a power plant regulated under the Clean Air Act.

The Obama Clean Power Plan would have given each state broad authority to determine how statewide obligations must be met within that state, with many states choosing to reach emissions and compliance targets by pushing power

companies to rely more on lower-emitting types of power generation, rather than focusing regulation narrowly “within the fence line” of a particular power plant. Allowing states to regulate emissions more broadly than facility by facility was a core concept.

The Trump EPA argues that the Clean Air Act prevents such an approach.

Any move to limit emissions on a facility-by-facility basis is more likely to keep aging facilities with greater emissions in service for longer. Coal would be the chief benefactor under the Trump approach because each state would have significant latitude to decide what each individual plant within its borders must do or not do to limit greenhouse gas emissions.

If the Trump EPA succeeds in the US Supreme Court some years from now, it could block future administrations from resuscitating the statewide approach used under the Clean Power Plan.

If Trump loses re-election, then a new Democratic administration could move to quickly reverse course.

Methane

The Trump administration announced at the end of August that it plans to eliminate any federal obligation for oil and gas companies to monitor and fix methane leaks from wells, pipelines and storage facilities.

The new methane rule would replace a stricter Obama-era rule.

Under the proposal, methane from natural gas would be regulated only indirectly and to a much lesser degree. A related category of gases called volatile organic compounds, or VOCs, would remain regulated under the new rule, which could still limit certain methane emissions.

The new rule must go through public comment and further agency review, potentially allowing it to be finalized in early 2020. Litigation is certain.

The new rule shines a light on a split within the natural gas industry, largely between small and large producers.

While smaller companies have complained that it is too costly to perform the required leak inspections, several major energy companies have openly opposed the new rule and called on the Trump administration to tighten restrictions on methane.

Since electricity production from natural gas produces only about half as much carbon dioxide as coal, some large companies worry that cutting back on industry obligations to restrict leaks could harm their industry’s image as a comparatively cleaner source of electricity.

While carbon dioxide is the most significant greenhouse gas, methane reportedly has 80 times the heat-trapping power of carbon dioxide during the first 20 years or so that it remains in the atmosphere.

Methane currently makes up nearly 10% of greenhouse gas emissions in the United States.

Clean Water Act 401

EPA proposed in August to scale back state authority under section 401 of the Clean Water Act to object to projects holding federal permits on grounds that they will harm state water quality.

The EPA proposal would narrow the actions that states can consider when determining whether a federally permitted project will violate state water quality standards. It would also limit the time for states to approve or reject a request for certification and allow federal agencies to veto state denials of water quality certification requests.

If finalized, the new Clean Water Act 401 rule will almost certainly land in court. If Trump loses in 2020, then any new administration would probably withdraw the proposal.

PFAS

EPA Administrator Andrew Wheeler said in late September that EPA is strongly opposed to Congressional efforts to impose federal cleanup standards for a class of chemicals that has been found to be contaminating drinking water.

Per- and poly-fluoroalkyl substances, or PFAS (pronounced PeeFAS), are among a group of fluorinated chemicals commonly added to a wide variety of consumer products to make them non-stick, waterproof and stain-resistant. These include carpets and upholstery, waterproof apparel, floor waxes, non-stick cookware, camping gear, fast-food wrappers, cleaners, dental floss and firefighting foams for putting out fuel fires.

There is an effort in the US House of Representatives to designate PFAS as hazardous in the pending 2020 defense authorization bill. The PFAS amendment was attached to the bill by a House subcommittee. The measure was before the full committee as the NewsWire went to press. The issue is expected to be decided in conference between the House and Senate. It has taken on partisan overtones. Democrats and Republicans in the House and Senate disagree over language and whether PFAS should be formally designated as hazardous substances under other environmental laws.

EPA released an “action plan” last February to address PFAS contamination. */ continued page 48*

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The plan calls for more research and initiates some water and waste regulatory steps, but does not set limits. It may ultimately prove to have been the first step toward nationwide drinking water standards being set for two of the most studied and toxic types of PFAS — perfluorooctanoic acid (PFOA) and perfluorooctane sulfonate (PFOS) — under the Safe Water Drinking Act, but Wheeler said as recently as September that no decisions have been made on whether to move forward with any rulemaking.

EPA must first propose a Safe Drinking Water Act regulatory determination for PFOA and PFOS before a maximum contaminant level could be set by the agency.

Wheeler suggested the amendment under consideration in the House would do more harm than good by designating the broad class of nearly 5,000 PFAS chemicals as hazardous substances, thereby subjecting each to regulatory restrictions.

“By putting the label ahead of the science, this bill will be nearly impossible to implement for many of the PFAS compounds,” Wheeler said.

He also said EPA could not meet the proposed timeline in the House amendment to complete a rulemaking within a year.

The eventual setting of drinking water standards and listing of certain PFAS as hazardous substances would probably lead to significant cleanup liability for responsible parties at sites across the country. It could even require responsible parties to do additional remediation at sites where cleanups related to other substances were previously determined to be complete.

In September, EPA granted approximately \$2 million to state universities to study the environmental impact of PFAS and identify procedures to manage the chemicals that enter the environment.

Whatever EPA does at a national level, a number of states have already entered the regulatory fray and additional state-level regulation is expected absent a move by the Trump administration to preempt them.

Meanwhile, a federal district court in Ohio rejected motions to dismiss a landmark class action tort lawsuit that seeks to force manufacturers to fund independent health studies and testing to determine the health effects of certain PFAS commonly found in the blood. The court has not yet decided whether to certify the class. The decision allows plaintiff to continue to try to build a scientific case for links between a variety of PFAS and adverse health effects, at least for now. ☺

— contributed by Andrew Skroback in New York and Washington

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