NORTON ROSE FULBRIGHT

PROJECT FINANCE
NewsWire
October 2018

How Safe Are Corporate PPAs?

by Howard Seife, in New York

Bankruptcy analysis has become a central part of due diligence on renewable and other power projects as project developers rely more frequently on corporate PPAs — long-term contracts with corporations to buy electricity — as a source of revenue for their projects.

A significant percentage of power contracts signed in the first half of 2018 for utility-scale wind and solar projects in the United States were corporate PPAs.

The Enron, Worldcom and Lehman Brothers bankruptcies showed that large companies can disappear quickly.

What happens when the power purchaser files for bankruptcy?

The bankruptcy of FirstEnergy Solutions last spring is a good case study.

Falling Power Prices

FirstEnergy Solutions was driven into bankruptcy by a set of problems that were unique to it. It owned power plants, but they were primarily coal and nuclear plants. Electricity prices have been driven down by cheap natural gas to a level that is making it hard for coal and nuclear to compete. The company was no longer earning enough revenue to cover operating costs.

The company is the competitive side of a business that is divided between a regulated side and a competitive side. The regulated side is the Ohio electric utility FirstEnergy. Both sides of the business are owned by a utility holding company whose */ continued page 2*

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US TARIFFS on many Chinese imports will increase automatically on January 1, unless any meeting between the US and Chinese presidents on the sidelines of the G-20 summit in Argentina in late November can diffuse trade tensions.

The United States has imposed three rounds of tariffs on Chinese products, and a fourth round is threatened on top of automatic tariff increases that have already been set in motion.

The US started collecting a 25% tariff on July 6 on a list of Chinese goods that accounted for $34 billion in imports last year. The $34 billion in products include “wind-powered electric */ continued page 3*

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shares are publicly traded. The bankruptcy filing had nothing to do with the regulated side or the public company. The only companies that filed for bankruptcy were those that were involved in the competitive side.

Those companies were separate special-purpose subsidiaries that were the owners of the coal and nuclear plants. FirstEnergy Solutions had also signed long-term contracts to buy electricity from independent power projects, primarily for renewable energy.

One of the benefits from a bankruptcy filing is it lets a company like FirstEnergy Solutions that is locked into uneconomic contracts to buy electricity reject the contracts.

There are two types of bankruptcy filings. In a chapter 11 filing, the bankrupt company presents a plan of reorganization that will allow it to get back on its feet economically. In a chapter 7 filing, the company is liquidated.

FirstEnergy Solutions made a chapter 11 filing. This gives it the ability to assume or reject contracts and, in this case, it is attempting to reject its PPA agreements. The company said in the bankruptcy filing that it is losing approximately $58 million a year on these contracts, and it estimates that the losses could be $765 million over the remaining terms of the PPAs. In addition, the company says that it no longer needs the power because of falling demand for electricity.

FirstEnergy Solutions is not the first competitive power supplier to file for bankruptcy. Two other notable examples in the last 20 years are Mirant, the competitive power affiliate of Southern Company, and Calpine, a competitive power company that managed to re-emerge from bankruptcy.

Rejection

There is enormous power in the bankruptcy court. Bankruptcy is an opportunity to try to reorganize the finances of power companies, but the court has to weigh the conflicting interests of the bankrupt company against those of creditors, contract counterparties and other stakeholders (including regulators and ratepayers).

The ultimate consumers of the electricity — the ratepayers — are unaffected. The bankruptcy court makes it a priority to ensure that electricity is still flowing to the local community under the same terms as before. Employees of the company will continue to be paid.

The parties who are most affected are the creditors of the bankrupt company and contract counterparties.

Unsecured creditors — for example, a bondholder — will stop receiving interest and principal payments after the bankruptcy filing and must wait until a plan of reorganization has been approved by the court to see how many cents they will receive on the dollar. That will play out over a period of time.

Contract counterparties can lose their contracts if the decision is made that the contracts are uneconomic for the bankrupt company.

It is important when entering into a long-term contract to know your counterparty. The market price for electricity can change over the contract term. A contract that looked good to the power purchaser when it was signed can be a bad deal five years later. Make sure the power purchaser is financially sound so that, even though the economics might shift, the company is expected to remain financially sound so that it will not be tempted to file for bankruptcy merely to get out of a few contracts.

In the FirstEnergy Solutions case, the PPAs were just one element in the decision to file. The parent holding company wants to focus on the regulated side, and the point of the chapter 11 filing is to sell the unregulated assets and shut down the nuclear plants.

Look during diligence at the power purchaser as a whole. Does it have a good business? It

Developers should try in corporate PPAs to anticipate what will happen if the customer files for bankruptcy.

is solvent? What could happen during the PPA term to cause the company to crash? How likely are those scenarios?

If, despite all of the precautions, the power purchaser seems headed for bankruptcy, review the PPA carefully to see what your rights are under the contract. If the power purchaser is in default, it might give the independent generator certain rights under the contract. For example, the generator may be able to ask for collateral like a letter of credit.

Act Early

This brings us to the concept of preferences under the bankruptcy code.

Suppose an independent generator gets a letter of credit. If the power purchaser files for bankruptcy within 90 days after providing the letter of credit, that is potentially a preference, meaning any draws could potentially be taken away in bankruptcy.

Therefore, act early in the process. Then sweat out the 90-day period so that whatever collateral is received to ensure performance of the PPA can be retained.

Apart from that, an independent generator has very limited recourse. It should start looking for other potential outlets for the electricity.

Wholesale power sales are subject to regulation by the Federal Energy Regulatory Commission. The FirstEnergy Solutions bankruptcy has illuminated the tension that exists between the regulators who want to flex their muscles and the bankruptcy court, which wants to exercise its jurisdiction. This fight between the regulator and the bankruptcy court has played out before in both the Mirant and Calpine bankruptcies.

The bankruptcy court wants to see the bankrupt company reorganize and wants to enforce the provisions of the bankruptcy code, while FERC wants to assert its power over the sale of electric power and the reasonableness of rates in the filed-rate doctrine, and it is charged with looking out for the public interest.

The bankruptcy court does not care so much about the public interest. Its goal is to see the company reorganize and have the creditors paid. FERC has a broader view. It wants to protect the market and consumers. These competing interests clash in bankruptcy.

These tensions landed before a US appeals court in the Mirant bankruptcy, and the appeals court decided to give primacy to what is good for the debtor.

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generating sets" falling under HTSUS (tariff classification) 8502.21.00, electrical transformers, electrical capacitors, circuit breakers, electrical switching apparatus, machine tools, industrial robots, ball bearings, gears, and DC and AC generators.

A 25% tariff took effect on August 24 on another 281 categories of Chinese products worth $16 billion, including iron and steel products, machinery, motors, electrical meters, insulated electric conductors, solar inverters and voltage regulators.

A 10% tariff took effect on September 24 on another 5,745 categories of Chinese products that accounted $200 billion in US imports last year. The tariff on these products will increase to 25% on January 1 unless the Chinese take action to reduce their trade deficit with the United States and address US complaints about technology transfers and intellectual property. The $200 billion list includes more Chinese iron and steel products, rubber, copper, zinc, nickel, lead, cobalt, more electrical transformers, various types of batteries, carbon electrodes, electrical insulators, electrical conduit tubing and various electrical machinery parts.

Chinese exports to the US in 2017 were $506 billion. The US is currently collecting duties on $250 billion. President Trump threatened in separate interviews in July to subject another $200 billion in Chinese products, and then all remaining products, to duties, but no list has been released yet. At some point soon, what is on the list will cease to matter if close to all Chinese products are covered.

China announced new tariffs on $60 billion of goods from the US levied at 5% or 10%, effective September 2, including honey, LNG and smoked salmon.

The Chinese renminbi has dropped nearly 10% in value since March against the US dollar, negating some of the effects of the US tariffs. The dollar has been strengthening against all currencies.

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In the Calpine bankruptcy, FERC was deemed to have a superior interest, and it was given the final say over whether a PPA can be rejected.

No bankruptcy case in the power sector has gone all the way to the Supreme Court to reconcile these conflicting rulings.

The bankruptcy court in the FirstEnergy Solutions case is following the precedent set in the Mirant bankruptcy. The decision has been made to focus on what is best for the debtor without giving much weight to the effects on third parties and the power markets generally.

The court said the debtor is free to exercise its business judgment to decide to reject the contracts. That decision is being appealed by FERC and some counterparties to the PPAs to a US court of appeals.

The Federal Energy Regulatory Commission takes the position that a PPA for the sale of wholesale power cannot be rejected in bankruptcy without involvement by FERC and that a bankruptcy court cannot approve such a rejection.

Any independent generator that is facing rejection of a power contract after the power purchaser has already filed for bankruptcy should do three things.

First, it should urge FERC to take an active role in the proceedings. Second, it should try to persuade the bankruptcy court to follow the Calpine precedent of ceding jurisdiction over the fate of any wholesale PPAs to FERC. Third, it should argue, if the bankruptcy court insists on retaining jurisdiction over the PPAs, that the standard to set aside such contracts should take into account the public interest, including the impact on independent generators. Could there be a ripple effect of other bankruptcies as independent power projects whose contracts are set aside are forced themselves into bankruptcy? These issues are being played out in the FirstEnergy Solutions case.

In addition, the independent generator should analyze what rights it has under the contract after a breach by the power purchaser. It may have a right to liquidated damages, and the damages could be substantial depending on how many years are left in the contract term. It may be able to negotiate a dollar amount for its claim if there is no formula in the contract. If not, then it will be up to the bankruptcy judge to determine damages.

The generator could end up with a very large damage claim, but how much it will actually be paid is another story. In chapter 11, secured creditors are paid first. Next come administrative claims for such things as employees and people supplying goods and services during bankruptcy. Unsecured creditors come last. Any damage claim under a rejected PPA is an unsecured claim.

To put this into context, FirstEnergy Solutions filed with $3.5 billion of funded debt. The unsecured creditors will be behind the portion of that debt that is secured and will have to share ratably in what is left. It is too early to tell how much money there will be to split among all the creditors with claims against the company.

Practical Advice

As the market moves to corporate PPAs, one thing to think about is whether it is possible to get collateral from the power purchaser to secure performance. Such collateral should withstand bankruptcy.

There are other things an independent generator can do. Think about a liquidated damages provision to avoid having to litigate in the unfortunate event the power contract is breached. Address who gets benefits that might otherwise belong to the power purchaser when the contract is terminated.

The enormous claims arising out of the wildfires that ravaged California last year are causing people to worry about what might happen to Pacific Gas & Electric. There have been determinations that falling power lines may have ignited some of the wildfires. Under California law, there is strict liability for power companies in that situation. The damages resulting from the fires have been in the billions of dollars. There has been loss of life, thousands of homes were destroyed, and various aggrieved parties are filing claims and lawsuits against PG&E.

PG&E has said publicly the claims could total $15 billion, and whether it would have the capacity to pay those claims is a big question. Whether it has the inclination to litigate all of those claims, which would be a very expensive and draining process, is another question. How much insurance the company has is another unknown.

PG&E had said publicly that it was considering a bankruptcy filing, as bankruptcy is a good forum to deal with tort claims of this nature.

PG&E has a large number of power contracts with independent generators that could face rejection in bankruptcy. However, a new law signed by the government in September may obviate the risk that PG&E will file for bankruptcy. The new law allows utilities to issue rate-recovery bonds to help pay the tort claims, with the ratepayers paying off the bonds through a surcharge on their bills. (For more details, see the "California Update" in this issue.) ◎

California Settles CCA Exit Charges

by Deanne Barrow, in Washington

The California Public Utilities Commission issued a highly-anticipated decision in October revising the formula for calculating exit fees that the three investor-owned utilities in California can charge customers who leave the utilities to become customers of community choice aggregators and other retail power suppliers.

The exit fees may determine how many customers move ultimately to CCAs.

The CPUC staff estimated last year that as many as 85% of California electricity customers may abandon the utilities by the mid-2020s for CCAs and other retail suppliers. Forecasts are for 25% of California electricity customers to be served by CCAs and other non-utility suppliers by the end of 2018.

The commission made changes that are expected to lead to an increase in the exit fees charged by the utilities, but it also set a cap on the potential increase. The decision tees up a second phase of the proceeding to consider competing arguments over how best to redistribute resources in the utilities' portfolios given a significant over-supply situation facing the utilities.

CCAs

CCAs are legal entities formed by cities, counties or a combination of cities and counties in order to provide electricity to local residents.

The incumbent utility, which no longer provides the electricity, still remains responsible for transmitting and distributing the power, as well as for billing, collection and other customer services.

The California legislature authorized the creation of CCAs in 2002 with the passage of AB 117. The first CCA was formed in 2010 and, since 2016, CCAs have been rapidly proliferating all over the state. Seven new CCAs have launched this year alone, bringing the total number to 19.

California law requires that the utilities' remaining customers be held harmless from the departure of other customers for a CCA.

Given the potential for huge load defection, the commission has been wrestling with what exit charges to require customers who abandon the regulated utilities to / continued page 6

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Separately, the US Department of Commerce announced changes in mid-September in how it processes applications from US importers for relief from a 25% tariff on steel imports and 10% tariff on aluminum that apply to imports from virtually all countries.

The process was a mess. Commerce requires a separate five-page form be filed by each importer for each individual product for which an exemption is sought. Thus, for example, if one importer wants exemptions for five products, it must file five separate applications. Trade associations are not allowed to apply for whole industries. An exemption granted to importer A on product X does not allow importer B to import the same product duty free. B would have to apply for its own exemption.

Commerce was expecting to receive 4,500 exemption requests for steel and 1,500 for aluminum. Instead, it received more than 38,000.

Senator Pat Toomey (R-Pennsylvania) said in a letter to Commerce Secretary Wilbur Ross that 2,900 requests had been handled as of August 23 when Toomey wrote the letter. Toomey listed 37 Pennsylvania companies he said are being harmed by the tariffs and need decisions about exemption requests that they or their suppliers filed. He said several of the companies were still waiting after he wrote about them four months earlier. He called the exclusion process "inefficient and unnecessarily burdensome" and said the tariffs are "taxes" imposed "under the false pretext of national security." Some steel and aluminum companies whom the tariffs are intended to help are in Pennsylvania.

Meanwhile, the US Trade Representative's office announced in a *Federal Register* notice on September 19 that it will exclude certain types of solar panels and cells from a 30% tariff the US started collecting on imported solar modules and cells on February 7. The exclusions cover a range of modules / continued page 7

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pay to help cover the cost of stranded assets that the utilities are left holding.

The commission determines annual values for the "power charge indifference adjustment" or PCIA (the formal name for exit charges) for Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric in each utility's annual energy resource recovery account forecast proceeding. In the years since adoption of the PCIA methodology, dissatisfaction has grown among the utilities and CCAs, both with the methodology of calculating the PCIA as well as with its numerical outcomes. In June 2017, the commission issued an order opening a rate-setting proceeding to review the current PCIA methodology. Over the course of the ensuing 14 months, the commission received comments from 28 entities or groups.

Customers exiting utility service in California are expected to pay higher exit fees after a CPUC decision in October.

Pared down to its essence, the PCIA is a calculation of the above-market costs of power contracts and utility-owned generating assets that are no longer needed by the utilities to serve departing load. Above-market costs are calculated by subtracting market value from gross costs of the relevant resources. Underlying most disputed issues in the proceeding was the question of portfolio valuation or determination of market value. The methodology for calculating market value varies depending on whether the resource is fossil-fuel based, renewable or resource adequacy. As discussed in further detail below, the commission made four changes to the former methodology.

Valuation of Resources

The first change was to revise the inputs used for calculating the market value of renewable and resource adequacy resources in utility portfolios.

Instead of relying on administratively-set benchmarks, renewable resources will now be assigned a value based on actual prices for purchases and sales of renewable energy by the three investor-owned utilities, CCAs and electric service providers.

Beginning in 2019, to ensure the commission has access to the necessary data to support the calculation, all retail electricity providers will be required to submit (under seal) price, volume and quantity data for purchases and sales of renewable electricity to the commission on an annual basis by January 31. The commission will then calculate market values based on transactions entered into during the year two years before the forecast year for delivery in the forecast year. For example, the PCIA for 2021 (which is calculated in 2020) will use data from transactions concluded in 2019.

Similar to renewables, resource adequacy resources in the utility portfolios will now also be assigned a value based on the sale price for such resources. A resource adequacy resource is a capacity commitment (utilities, CCAs and other load-serving entities must show state regulators that they have enough capacity commitments to be able to meet all of their customers' energy requirements plus a minimum reserve requirement). The data will be pulled from the commission's most recently published resource adequacy report, which compiles price data provided by retail electricity providers on a confidential basis. For example, the 2017 resource adequacy report reflects data from 5,347 monthly contract prices reported by the three investor-owned utilities, 14 other retail electricity suppliers and 12 CCAs.

Other Changes

The second change the commission made was to order the utilities to conduct an annual true-up process to reconcile differences between the actual versus the forecast above-market value of PCIA-eligible resources.

Each utility will need to establish a balancing account with three sub-accounts to track the costs and revenues associated with fossil fuel, renewable and resource adequacy generating resources.

At the end of the year, the net costs of PCIA-eligible resources will be calculated based on the recorded gross costs of the resources minus the revenues such resources earn in relevant markets, as tracked in the balancing accounts.

Any year-end under-collection or over-collection will be incorporated into the PCIA rate calculation in the following year.

The third change the commission made was to adopt a cap limiting increases in the PCIA from one year to the next to 0.5¢ a kilowatt hour. In the past, significant annual swings in energy prices have led to significant annual swings in the PCIA rate, making it challenging for the CCAs to engage in long-term resource planning. The cap is supposed to protect against such volatility.

The commission also authorized prepayment of the PCIA.

CCAs now have the option of prepaying the PCIA on a one-time basis on behalf of their customers so that the customers will be relieved of the PCIA burden going forward.

This approach has some historical precedence. In 2007, the commission directed the investor-owned utilities to permit California municipal utilities to prepay departing load obligations as a negotiated lump sum (see CPUC Resolution E-3999).

Several commentators noted that in practice, making a prepayment will be tricky because of the uncertainty involved in forecasting the above-market costs over an extended time frame. However, the commission emphasized that it was not requiring the utilities to accept any estimate of a customer's long-term cost responsibility, only that they negotiate in good faith with counterparties.

Any prepayment arrangements will need to be submitted to the commission for approval on a case-by-case basis.

The fourth change the commission made was to lift an existing limit on cost recovery to costs incurred during the first 10 years of operations for utility-owned power plants built or acquired after 2002.

The trade association CalCCA, which represents all of the operating CCAs in the state, says lifting the 10-year limit will cause system-average PCIA rates for 2019 to increase by 17% for PG&E and 42% for SCE. The commission tried to mitigate against such increases by requiring utilities to recognize CCA load in their resource planning and directed they not sign power purchase agreements that might create new liabilities where available information suggests the power might not be needed.

PCIA Alternatives

The commission will now turn to considering longer-term solutions to redistribute excess power supply held by the utilities in phase two of the proceeding. / continued page 8

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and cells used in smaller applications, including interdigitated back contact (IBC) solar modules and cells made by SunPower.

The USTR said it received 48 product exclusion requests and 213 subsequent comments about them. Decisions have not been made about other products.

For more detail about US duties, see "US Solar Tariffs" in the February 2018 *NewsWire*, "Tariffs: Effect on US Power Sector" in the April 2018 *NewsWire*, "Tariff Threats" in the June 2018 *NewsWire* and "US Import Tariffs Remain a Challenge" in the August 2018 *NewsWire*.

REPORTED FAIR MARKET VALUES for solar projects are continuing to decline.

The median fair market values claimed for utility-scale solar projects of five megawatts or larger in 2017 were $1.60 a watt DC and $2.00 a watt AC, according to the latest "Tracking the Sun" report released by the National Renewable Energy Laboratory in September.

NREL said it did not find the economies of scale it expected when comparing small projects to large projects. There were some. The median price for projects in the 50- to 100-megawatt range was $1.35 a watt. It was $1.49 a watt for projects between 100 and 200 megawatts. NREL said this may be because really large projects take longer to build and equipment costs may have been locked in some time ago.

NREL said these numbers reflect a "top-down approach" of accepting reported market values of completed projects in tax equity deals and direct sales. If a bottom-up approach is used of building up costs to construct, it said the national average (mean) of 100-megawatt projects in 2017 was $1.03 in non-union states and $1.13 a watt in union states.

Wood Mackenzie, a consultancy, said in its "Solar Market Insight" report in September that the average cost to build a utility-scale project with a single-axis / continued page 9

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Several proposals are on the table.

One is to hold an auction in which power purchase agreements held by the utilities would be sold to CCAs. Another is to assign the utility power contracts to the CCAs.

A third proposal recommends allowing the utilities to securitize buy-outs and buy-downs of contracts the utilities signed to comply with the state renewable portfolio standard through a bond offering and then pass through the bond payments in customer rates. Under such deals, a party selling power to the utilities would accept cash consideration in exchange for terminating a PPA (in the case of a buy-out) or in exchange for reducing the price for electricity sold during the remaining years of the PPA term (in the case of a buy-down). The costs of such buy-outs or buy-downs would be recovered through a special surcharge on utility bills. The utilities would issue bonds backed by ratepayers' obligations to pay the surcharge.

Utility bonds are considered very low-risk due to the non-bypassable nature of the surcharge supporting the debt. As such, they pay lower interest (around 3% to 4%) than the utilities' cost of capital (around 7.5%). According to the trade association CalCCA, this approach has been successfully implemented in New Hampshire and authorized for use in Vermont. California also used a similar approach to cover utility stranded costs after the California energy crisis in the early 2000s.

Impact on Power Projects

Lenders and investors in private power projects that have power contracts to sell electricity to CCAs are aware of the risk that the exit charges could drive customers back to the regulated utilities.

In the face of this risk, some lenders require cash sweeps in credit agreements that get triggered if customer opt-out rates increase beyond a certain level measured from negotiated baseline levels.

The commission's decision could be seen as lessening the risk of opt-out because, among other things, it places a cap on year-on-year increases in the PCIA and allows one-time prepayment of the PCIA. The commission itself noted that the new methodology ensures a reasonably predictable outcome in the level of the PCIA, which will provide certainty and stability for all customers within a reasonable planning horizon.

It remains to be seen whether lenders will be willing to relax their requirements tied to changes in opt-out levels.

In terms of PPAs, it is too early to tell if the commission's decision will affect pricing.

In terms of credit support, CCAs have historically resisted posting security and providing collateral support to sellers under PPAs despite credit and regulatory risk, and we do not expect the commission's decision to affect this position.

On an operational basis, the historic volatility of the PCIA has led many CCAs to establish significant reserves and rate stabilization funds to buffer rates in the event of increases to the PCIA so that the CCAs can remain cost-competitive with the utilities. If CCAs perceive the PCIA as less volatile and more predictable following the commission's decision, then some of these funds could get re-deployed toward investments in energy and infrastructure projects and wholesale power procurements. ◎

Representations and Warranties Insurance

by David E. Barrett, in New York, and Scarlet McNellie, in Dallas

A representations and warranties insurance policy, or RWI, is insurance that covers the losses that arise from a breach by the seller of its representations and warranties in an acquisition agreement.

This type of insurance is becoming more common in mergers and acquisitions.

The policy itself may be issued to the buyer in an acquisition and thus be referred to as a buy-side policy, or it could be issued to the seller and be referred to as a sell-side policy. The vast majority of policies currently issued are buy-side policies.

Through RWI, the insured can recover directly from the insurer for losses rather than from a party in the transaction. Thus, the insurance policy shifts the risk of loss from the seller to an insurer. By using this product, the buyer and seller can limit, or even sometimes eliminate, the seller's potential liability for breaches of representations and warranties, while at the same time protecting the buyer from the risk of loss.

There has been an increase in the last year or two in the use of this type of insurance.

Some sellers warn bidders in asset or company auctions that the seller will not give much in the way of indemnities and the buyer will have to rely on representations and warranties insurance.

The increase in interest in this type of insurance is due partly to the fact that the types of transactions that can be covered by representations and warranties insurance now have expanded beyond simple industrial or manufacturing targets to a broader range of targets, including those in the energy and project finance sectors.

As the scope of the coverage expands, buyers and sellers are finding the product a more useful tool to address deal issues like survival periods for representations.

Another factor in the growing use of the product is many new insurers are coming into the US market. This has increased competition and put downward pressure on the premiums the insurers charge.

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tracker was a little over $1 a watt in the first quarter 2018, falling to a little under $1 a watt in the second quarter.

Turning to residential rooftop systems, the national median price in 2017 was $3.70 a watt, according to NREL. It was $3.10 a watt for smaller C&I systems, and $2.20 a watt for larger such systems. The line between small and large is 500 kilowatts.

Installed prices in the US are higher than in other markets. NREL said typical pricing for residential systems in Australia was around $1.80 a watt in 2017, around half the median price in the US. The median price in Germany was lower still at around $1.50 a watt.

Installed prices vary widely among US states. State-level median prices ranged from $2.60 to $4.50 a watt for residential systems, from $2.20 to $4.00 for small C&I systems and from $2.10 to $2.40 a watt for large C&I systems. High prices in California, Massachusetts and New York pull up the averages.

NREL said third-party-owned residential systems, where the solar company retains ownership, have a median installed price that is 50¢ a watt less than where the homeowner buys the system directly. It said this may be because solar companies buy in bulk and face lower equipment costs. It found no difference in C&I systems based on ownership.

Meanwhile, EnergySage, an on-line market for consumers for rooftop solar systems, said in early October that rooftop systems were selling for $3.12 a watt in the first half of 2018 and seven out of 10 buyers want batteries as part of their purchases.

Consultancy Wood Mackenzie put the average price at 3.01 a watt during the same period.

A FLOOD OF US WIND PROJECTS should come to market over the next two years.

US installed wind capacity was 90,004 megawatts at the end of */ continued page 11*

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Cost

Just a few years ago, RWI premiums ranged from 3% to 5% of coverage limits and the retention, which is another term for the deductible, ranged from 1.5% to 2% of deal value. More recently, premium and retention amounts have steadily decreased.

Buyers of RWI may now find premiums below 3% of coverage limits and retention amounts of 1% of deal value or even less for larger transactions.

Given that the buyer most often purchases the policy, one would expect that the buyer would pay the premium. However, this cost is almost always negotiated between the buyer and seller as a transaction expense. Sometimes the buyer and seller agree to split the cost 50-50.

In terms of who takes the first loss, the deductible is often split so that the buyer bears the first half of it and then the seller is at risk for the second half. In essence, the retention is split. The first dollar is at the buyer's loss, but the seller will bear some of that exposure so that the seller has some "skin in the game" in terms of its exposure to breaches of the representations and warranties.

The cost of representations and warranties insurance is falling as more insurers enter the market.

Underwriting Process

The process of buying RWI insurance has become more streamlined and efficient over the last couple years. Today an RWI policy can be bound in as little as a week, although two to three weeks is more common.

The process usually tracks the time it takes to negotiate a transaction agreement. The process starts typically with a broker who specializes in this type of insurance seeking quotes from insurers. Insurers will submit non-binding indication letters called NBILs that will include information about the amount of coverage, premium, retention amount, proposed exclusions and areas of heightened risk that will be focused on during the diligence process. Some insurers may offer pricing options: for example, the NBIL will explain the effect on the premium of having a limit on liability $10 million versus $20 million or a retention amount of 1% versus 2%. The broker then helps the buyer evaluate the quotes, both in terms of pricing and the proposed exclusions. The broker and buyer usually end up jointly selecting the preferred carrier.

Once the carrier has been selected, an underwriter will be assigned if one was not already involved in preparing a quote. The underwriter looks at the acquisition agreement, the disclosure schedules and all the due diligence reports. The majority of underwriters also engage outside legal counsel to assist with the review, but there are some that do everything in-house.

After the diligence is completed, the broker and underwriter will schedule an underwriting call, that typically runs for about two hours, to allow the underwriter and its counsel the opportunity to ask questions about how the deal negotiations went, the deal terms and the diligence performed, and probe into matters that are of potential concern. The persons buying the insurance should spend time preparing for the underwriting call.

The best way to prepare for the underwriting call is to review the agenda and questions, if provided ahead of time, and make sure that the right people are on the call to provide answers. Have someone from the deal team on the call to discuss the business of the target and rationale for the deal. Have someone from the operational team who performed any operational diligence. Have the legal counsel who negotiated the agreement and performed legal diligence. Have a financial adviser who did the financial and quality-of-earnings diligence.

Have a tax adviser who did tax diligence and can speak to the structure of the transaction and tax history of the target. Finally, it may also be useful to have subject matter specialists, like an environmental or regulatory lawyer, depending on what questions the insurer has said it has about the transaction.

The underwriter is more likely to take comfort in the answers if the buyer exhibits a thorough understanding of the deal and shows that thorough diligence has been done.

The underwriter will send a list of written follow-up questions after the call. These are questions about things that could not be answered during the call as well as any transaction-specific exclusions from the policy that have resulted from the underwriting process and review. The underwriter will also provide a copy of the draft policy if it has not already done so.

From this point, the buyer will simply address all the remaining follow-up questions and negotiate the policy. It is worth noting that the underwriter will want to review all subsequent drafts of the agreements and disclosure schedules, and any other materials that are produced, until the point when the deal is ready to be signed and the policy is bound, which typically occur at the same time.

Underwriters will expect to have very substantial third-party due diligence in place. They will expect an outside law firm or multiple firms to have done a robust due diligence review of the legal matters. They will want to see that an accounting firm has done a quality financial and tax review.

If the transaction is in an area like the energy industry, where specialist knowledge is needed to understand the potential risks, then the underwriters may expect also to see an independent engineer, environmental and permitting expert and possibly other consultants. The diligence is usually done by third parties. It is not done by the buyer.

However, if the buyer is a large institution that can demonstrate it has the expertise in-house, then there will be less need to have third-party reviews. If the buyer is a financial investor like a private equity firm, then the insurer will want a full third-party diligence review. Even with a large institution that has the experience to evaluate the deal on its own, third-party reports are preferred.

Coverage

RWI coverage is intended to cover the typical representations and warranties that would be given by a seller in an M&A transaction and be indemnified by the seller. The policy also covers liabilities for pre-closing taxes as a separate indemnity.

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the second quarter of 2018, according to the American Wind Energy Association. There were wind farms in 41 states, with Texas, Oklahoma, Iowa and California having the most installed capacity. Texas had 23,262 megawatts, or a little over 25% of total US capacity. Wind accounted for 6.5% of US electricity output.

Another 37,794 megawatts of projects were under construction or in advanced development. Of that number, 18,987 megawatts were under construction and another 18,806 megawatts were in advanced development, meaning the developer had signed a power purchase agreement or a turbine supply agreement for the project. The projects under construction or in advanced development are in 33 states, with 21% in Texas and 31% in the Midwest.

More utilities are getting into the act by building projects themselves or acquiring projects from developers under BOT or build-own-transfer arrangements. The top five utilities are Berkshire Hathaway Energy — which owns MidAmerican, PacifiCorp and NV Energy — Xcel, American Electric Power, Alliant Energy and Great Plains Energy.

A significant number of new power contracts are being signed this year by developers. A total of 4,600 megawatts of new utility PPAs and 2,700 megawatts of new corporate PPAs were signed in the first half of 2018 to sell electricity from wind farms.

MAKE, a consultancy, estimates that the US will install 8,000 megawatts of new wind projects in 2018, 11,000 in 2019 and 12,000 in 2020, before dropping to 7,000 in 2021. The consultancy arm of Swiss bank UBS is a little more optimistic, estimating new capacity additions of 11,000 megawatts in 2018 and 12,000 in each of 2019 and 2020, before dropping to 8,000 in 2021. Most remaining wind farms must be in service by the end of 2020 to qualify for federal tax credits at the full rate.

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Reps and Warranties

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However, the policy does not cover everything that an indemnity in a transaction agreement would normally cover.

For example, it does not cover breaches of covenants. It does not usually cover any special indemnities that are agreed during negotiations outside the standard indemnities. Thus, in most deals, even though there is representation and warranties insurance coverage, the seller indemnity will still be part of the transaction because it needs to cover the deductible and needs to cover covenants, special indemnities, potential exclusions from the RWI policy and other matters.

The presence of an RWI policy affects the seller indemnity in a significant way, but it does not eliminate the need for a seller indemnity. That said, lately as RWI policies become more prevalent in transactions and also in an environment that is more seller friendly from a deal perspective, with seller leverage increasing and competitive auction processes, some transaction agreements have no seller indemnity, and the buyer relies exclusively on insurance.

In transactions without a seller indemnity, the representations and warranties will not survive past closing, and the buyer essentially bears all the risk that is not covered by the RWI policy. The only recourse the buyer has for a seller misrepresentation is against the policy above the retention amount and to the extent there is no exclusion in the policy.

The insurers try to write policies that cover all the representations and warranties in the acquisition agreement. That said, the insurers are expecting the representations to look like the normal representations one would get in any deal. They may not want to cover any representations that are off market.

There are some representations that are in a minority of deals that some might argue are market for that type of deal, but that the underwriters generally exclude as a matter of practice. An example is a representation that there has been full disclosure by the seller of all material information or a variant based on the Securities and Exchange Commission anti-fraud Rule 10b-5. These types of representations are almost always excluded by an underwriter.

Another representation that is usually excluded is any representation that the target company is not insolvent and will not be rendered insolvent by the transaction. Underwriters do not feel in a position to evaluate the solvency of the target. Another example of a representation that is not covered is collectability of accounts receivable.

In general, underwriters do not want to cover representations that are so broad that they could cause losses that are at the maximum limits of the policy. They prefer to cover representations that are specific and targeted, and for which the potential exposure can be understood and quantified.

An example where the exposure can be understood is a representation that the target has not paid bribes to foreign government officials or otherwise violated the US Foreign Corrupt Practices Act. That type of risk can be understood by doing diligence. If the target company is operating in a high-risk jurisdiction or is engaged in contracting with foreign governments, then there will be more focus placed on the diligence done to confirm that there are no real risks in that area.

Policy Amounts

The insurers are fairly flexible on the amount of coverage that can be purchased. There is no magic formula, although most buyers look to buy coverage for about 10% of the purchase price. They may go up to 20% if they want larger coverage.

Fundamental representations are subject to a policy limit, which might be 10% of the purchase price paid in the acquisition. In the acquisition agreement itself, it is customary to have caps on the indemnity the seller may be required to pay. The cap for loss due to a breach of a fundamental representation

Brokers report it is more common lately to find M&A buyers relying after closing solely on reps and warranties insurance.

— for example, that the seller owns what it is purporting to sell or that it has authority to enter into the transaction — is typically the full purchase price, if there is a cap for breach of such a representation. Lower caps would usually apply to indemnities for breaches of representations that are not considered as fundamental.

The point is that by taking on an RWI policy and agreeing to look to the insurance rather than the seller for indemnification, you are losing any enhanced coverage for fundamental representations that you might otherwise have been offered in the acquisition agreement.

Getting coverage through insurance for fundamental representations, in a way that the buyer would expect from the seller absent insurance, has been a challenge. Fundamental representations are things that are so fundamental that if untrue, the deal really should be unwound. However, some new insurers coming into the market are offering a special coverage for fundamental representations only that give the policyholder coverage for up to 100% of the purchase price. It is a type of excess coverage above the normal policy limits. The buyer must pay extra, but it is available if the buyer wants to close that gap.

Exclusions

The policy will have a list of exclusions or risks that it does not cover. For example, it does not cover known issues. If there is a known litigation, it will not be covered by the policy. Matters that are disclosed on the seller disclosure schedule are not covered by the policy nor are material issues that are raised during due diligence.

Thus, if there are known risks, the buyer should be prepared to find another way to address those than relying on an RWI policy.

For example, the seller might agree to a special indemnity, sometimes supported by an escrowed holdback of part of the purchase price or other credit support. Alternatively, the parties might decide to reduce the purchase price to address a known risk.

There are some special considerations for RWI policies in the energy area. It is important to keep in mind that this type of insurance has historically covered transactions that involve manufacturing and other light industrial companies. Covering energy and project-type deals is a more recent development, and many underwriters are new to the area.

Anyone buying insurance for an energy project should be prepared to spend time educating the / continued page 14

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THREE SOLAR TRANSACTIONS landed in court.

One is headed to trial next February 4 in the US Tax Court.

Solarmore Investments Inc. and a tax equity investor formed a partnership that bought 192 mobile solar platforms from DC Solar Solutions MFG. Inc. for $28.8 million, or $150,000 each.

The partnership was a standard partnership flip transaction, but with a fixed date for the flip five years after the mobile solar platforms were purchased.

The partnership paid the seller only 25% of the purchase price and gave a 20-year note for the balance that requires fixed payments of $134,331.40 a month.

The tax equity investor agreed to contribute 84.18¢ per dollar of investment tax credit to help cover the purchase price for the mobile platforms. The investor contributed the 25% of the purchase price paid in cash. It made only 2.8% of its investment before the equipment was put in service.

The sponsor, Solarmore, agreed to make capital contributions to refund the tax equity investor its money to the extent the tax credits are less than expected. If the tax credits are more than expected, then the tax equity investor must invest more. Solarmore also had to buy insurance for the value of the tax credits.

The partnership claimed a 30% investment tax credit on $28.8 million and also claimed a 100% depreciation bonus.

The sponsor, Solarmore, and the seller of the mobile solar platforms are related companies: they have 79% overlapping ownership.

The partnership leased the equipment for five years to another Solarmore affiliate for fixed rents of $140,000 a month plus 5% of the annual revenue from the affiliate's use of the solar platforms above $1.9 million. The IRS says the revenue from renting the mobile platforms to customers was insignificant.

The government asserts that no real partnership was formed. / continued page 15

Reps and Warranties

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underwriters about the types of risks in such deals. The underwriter in these types of deals will almost certainly bring in an outside law firm to help evaluate the diligence and identify the risks. The underwriter might rely more heavily on counsel than usual.

In these situations, buyers need to take a more comprehensive approach and lay out the risks in diligence reports in a manner that someone who is new to the area can follow. The underwriter will take more comfort from a report that it can understand. The lawyers and others doing diligence should get advice from the broker at what level of comprehension to write a diligence report that is as much for the insurance underwriter as the buyer in the M&A transaction.

Claims

There has not been a long claims history because the product has not been offered in the volume that it is today. That said, there have been a lot of claims made. Claims are more likely to be made under an RWI policy than made against sellers in cases where there is no RWI policy in place.

The insurers are well prepared to deal with claims. That is part of their line of business. They have entire groups within the insurance company who deal with claims. They have processes in place to pay out claims, and they are used to paying out claims.

Buyers in the M&A market are getting more comfortable that insurers do indeed pay on these claims and are capable of assessing and making appropriate decisions on the payment amounts after claims are made.

This is an area to watch. If claims begin to exceed what insurers expect, then it will obviously affect pricing and availability of the product. This is all the more reason for buyers and sellers in the M&A market to do a serious negotiation, allocate risks appropriately and do thorough diligence as if they will not be able to rely on insurance because that is what is most likely to lead to a stable market going forward. ◎

Special US Tax Rate for Pass-Through Income

by Keith Martin, in Washington

Individuals have to pay US income taxes on only roughly 80% of the income they receive from partnerships, S corporations and other pass-through entities.

The actual percentage is complicated to calculate.

The tax law has "guardrails" to prevent investment managers, lawyers, doctors, and other professionals from qualifying.

The Internal Revenue Service filled in a lot of the detail in proposed regulations in August.

It estimated the average time individuals will need to figure out how much of a tax break they qualify for each year on pass-through income will vary from 30 minutes to 20 hours.

Deduction

Partnership and S corporation income is reported on schedule E of individual tax returns in the US. Partners and S corporation shareholders will be allowed to deduct a percentage of that income, thus paying tax only on what remains.

The deduction is 20% of such partnership and S corporation income.

However, it may be less.

First, the deduction cannot exceed 50% of the partner's or shareholder's share of the wages paid by the business to employees as reported on W-2 forms sent to the IRS. If greater, the partner or shareholder can use as his or her cap 25% of wages plus 2.5% of the depreciable basis in property being used in the business.

This wage cap only applies in years when the partner or shareholder earns more than $415,000 (on a joint return, or $207,500 if single). For individuals with income in a "phase-in range" of between $315,000 and $415,000 (on joint returns, or $157,500 to $207,500 if single), the 20% deduction he or she can claim is subject to an alternate adjustment.

Second, regardless of income level, the deduction cannot be more than 20% of the ordinary income the partner or shareholder reported for the year from all sources.

Third, no deduction at all may be claimed on income that individuals earning more than $415,000 a year (on joint returns, or $207,500 if single) receive from law, accounting, brokerage and consulting firms, medical practices and other businesses where the principal asset is the "reputation or skill of 1 or more of its employees." The deduction is also not available to investment management firms, traders and dealers in securities, partnership interests or commodities. The IRS calls any service-type business that falls in these categories an "SSTB" for specified service trade or business.

Anyone with an income in the phase-in range of between $315,000 and $415,000 a year (on a joint return, or between $157,500 and $207,500 if single) can claim some deduction on income from SSTBs, but not the full amount.

Income Level

An individual trying to figure out how much pass-through income can be deducted should start with his or her taxable income from all sources for the year.

If it is below $315,000 (for a joint return, or $157,500 if single), then the calculation of the deduction is fairly straightforward.

The deduction is 20% of the income from pass-through businesses, but there are complicated rules for what can be counted as such income. For example, no deduction can be claimed on capital gains and dividends received by a partnership and then passed through to a partner. No deduction can be claimed on employee wages or on amounts that a partner is paid by a partnership in his or her capacity as a partner for services. There are special rules for investments in master limited partnerships and real estate investment trusts.

The deduction for each separate "trade or business" conducted through a partnership, S corporation or other pass-through entity must be calculated separately.

The IRS has not decided whether disregarded entities — single-owner LLCs that do not exist for tax purposes — should be ignored in deciding the number of separate businesses.

Businesses can be combined. It is up to the individual which businesses to combine. This is less meaningful for individuals with incomes below the phase-in range, but for others, it may help with the wage cap to combine businesses as this may lead to a higher overall deduction.

Businesses can only be combined if the same group of people owns at least 50% of each business being combined. None of the businesses being combined can be an SSTB. The businesses must be linked by having at least two of three features in common: the businesses must provide the same products or services or offer items that are customarily offered together, they must share facilities or central office staff like */ continued page 16*

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The IRS disallowed the tax benefits the tax equity investor claimed on audit. It said the investor was not a real partner because it was protected from downside risk since it will get its money back to the extent the tax credits are less than expected, and it has no upside potential since the lease rents are fixed.

What happens after the flip is important to any such analysis. In this case, Solarmore can repurchase what will then be a 5% partnership interest from the investor for the fair market value of the interest at the time. If this call option is not exercised, then the investor can "put" the interest to the partnership for the fair market value or the investor's capital account, whichever is less, with the repurchase price to be paid by the partnership over time out of 90% of distributable cash until paid in full.

The government is also disputing the tax basis the partnership used to calculate tax benefits. Solarmore produced appraisals from two appraisers confirming a market value of $150,000 per solar platform. The IRS says the platforms cost only $7,000 a piece to build and that adding royalty payments to the owner of Solarmore for use of a patent would push up the cost to only $13,000 per platform.

The IRS position is that the market value can be used as the tax basis for calculating tax benefits only in a sale between unrelated parties or in an inverted lease. It said otherwise the taxpayer is limited to the cost to build the platforms.

Finally, the government suggests that 75% of the purchase price should be ignored because it is circled cash among the Solarmore principals.

The case is *Solar Eclipse Investment Fund III v. Commissioner.*

Separately, a federal district court in Colorado ordered two companies in late August to repay the US Treasury three times the cash grants — also known as section 1603 payments — that the companies received on 41 solar rooftop projects, plus pay */ continued page 17*

Pass-through Income

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accounting, human resources or legal staff, or they must be operated in coordination with one another such as occurs when there are supply chain dependencies.

Once the decision is made to combine two or more businesses, then those businesses must be reported together in all future years absent a change in facts or circumstances.

Individuals may be taxed at a lower rate on income received through partnerships and S corporations.

The bottom end of the phase-in range is adjusted annually by the "chained" consumer price index. Use of the chained CPI will lead to smaller inflation adjustments because it takes into account that consumers substitute cheaper products as the cost of their regular baskets of goods increases. The figure $315,000 for a joint return and $157,500 if single are the 2018 figures. The inflation adjustments will start in 2019.

The top end of the phase-in range is $100,000 higher than the bottom end (for joint returns, and $50,000 if single).

Higher Incomes

Individuals with taxable incomes in or above the phase-in range must jump through more hoops to get any deduction.

The first step is to determine whether the partnership or S corporation is a type of business called an SSTB on which no deduction is allowed. Individuals with taxable incomes for the year from all sources above the phase-in range get no deduction. Individuals with incomes in the phase-in range get a partial deduction. The deduction phases out as the person's income moves across the phase-in range. Thus, for example, a person filing a joint return and earning $375,000 from all sources in 2018 qualifies for only 40% of the deduction, since such a person is $60,000 into a phase-in range of $100,000.

Businesses performing services in the following fields are considered SSTBs: law, accounting, actuarial science, performing arts, consulting, athletics, financial services, brokerage services, trading, investing and investment management, and dealing in securities, partnership interests or commodities. Electricity is a "commodity." However, partnerships selling electricity from a power plant are not considered dealers. A dealer is someone who both buys and sells a commodity.

Congress added a catch-all category that picks up any business that relies on the "reputation or skill of 1 or more of its employees." However, the IRS said it would only put in this category pass-through income earned from endorsing products or services, earning appearance fees or earning licensing fees from use of an individual's name, voice or other likeness.

Real estate and insurance agents and brokers were given a pass. They are not considered engaged in SSTBs.

A pass-through business that does a mix of things can still be labelled an SSTB. A business with $25 million or less in gross receipts will not be treated as an SSTB if SSTB-type services account for less than 10% of the gross receipts. The 10% cap falls to 5% for pass-through businesses with more than $25 million in gross receipts. A Treasury lawyer said at a conference in early October that the 10% and 5% caps are a cliff. A business that is slightly over will be an SSTB, unless a way can be found to treat the SSTB-type services as earned in a separate business.

The next step is to calculate the deduction. This starts the same way as for individuals with lower incomes: it is 20% of the income from pass-through businesses, but with complicated rules for what counts as such income and with the need to calculate the deduction separately for each business, although some businesses can be combined at the option of the taxpayer.

However, the deduction from each business or combination of businesses is capped.

The cap is 50% of the W-2 wages reported by the business to employees or, if greater, 25% of the W-2 wages plus 2.5% of the basis in depreciable property.

Each partner in a partnership is allocated a share of the W-2 wages. The cap on a partner's deduction is 50% of the wages the partner is allocated. This could be a challenge for developers of renewable energy projects that are in tax equity partnerships where the developer is a pass-through entity owned by individuals because the W-2 wages, like other tax losses, may be allocated almost entirely to the tax equity investor.

The basis in depreciable property is the original cost, ignoring any depreciation claimed. Thus, for example, if an asset cost $100 and $60 in depreciation has been claimed, absent a transfer of the asset for tax purposes, the basis used to calculate the pass-through deduction is $100.

However, the basis is no longer counted after 10 years or, if longer, the MACRS recovery period. Thus, for example, the basis in a transmission line with a voltage of 69 kV or greater that usually has an MACRS recovery period of 15 years would be counted for 15 years. A wind farm or solar project usually has an MACRS recovery period of five years. The basis to calculate the pass-through deduction is not affected by the fact that an investment tax credit was claimed on the project.

Many power projects are owned by partnerships. Any "step up" in basis that an individual receives via a section 754 election after buying a partnership interest is ignored. When a project is contributed to a tax equity partnership, the partnership keeps the same basis and continues counting down the 10 years (or longer recovery period) that the contributing partner had on whatever share of the project is considered contributed.

Renewable energy projects throw off losses for the first three or four years. If a business (or combination of businesses) has a loss for the year, then the loss must be allocated across the other pass-through businesses owned by the individual in proportion to the positive income from each such business. It will reduce his potential pass-through deduction on income from the other businesses.

The W-2 wages and depreciable basis from any business with a loss for the year are lost. They are not allocated to the other businesses. */ continued page 18*

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an additional penalty of $225,000. The companies received $1.6 million in grants. They have been ordered to repay the government $4.8 million for submitting false claims to the US Treasury.

Infinergy Solar and Wind, Inc. partnered with dealers who installed solar panels for residential and commercial customers and then invoiced Infinergy for them, but without expecting full payment. The dealers said the invoiced amounts did not match their real costs, and Infinergy would sometimes tell them the invoices were too low and should be increased.

Infinergy would then purport to sell the systems to an affiliated company, New World, at a markup. New World did not actually pay Infinergy, but reported the sales prices as its tax basis when applying for cash grants.

Ellen Neubauer, the Treasury cash grant program manager, sent an email at one point to Murray Hambrick, the owner of both companies, warning him that claimed costs must actually be incurred.

New World purported to lease the systems or sell power from them to customers, but it failed to collect payments in many cases, and Hambrick "admitted that he was not concerned with the payments."

Hambrick did not fight the claims against the companies, and the court issued a default judgment. However, he is fighting claims against himself. His counsel told the government that he plans to file for bankruptcy in the hope of avoiding personal liability.

In the third case to land recently in court, a federal district court in Utah ordered two men and their Utah companies RaPower-3 LLC and International Automated Systems, Inc. in early October to repay a little over $50 million and refrain from further activity after what the court said was a "massive fraud" involving sales of solar lenses that the promoters said entitled the owners to claim investment tax credits and depreciation that far */ continued page 19*

Pass-through Income

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Other Features

The deduction takes effect in 2018. It ends after 2025.

Investors in master limited partnerships benefit from special rules. They can deduct not only as much as 20% of income allocated to them by the MLP, but also gain from the sale of MLP interests to the extent the gain is taxed as ordinary income.

Partnerships and S corporations will have to report to partners and shareholders the information they need to calculate their deductions. This includes whether the business is an SSTB, how much income qualifies potentially for the 20% deduction and what each partner's share is of W-2 wages and depreciable basis.

The same pass-through deduction can be taken for calculating the alternative minimum tax. ◎

Financing Storage and EV Infrastructure

by Ren Plastina, with Investec in New York

Battery storage, electric vehicle infrastructure, community solar, micro-grids and fuel cells are emerging markets on which lenders like Investec are focused as potential growth areas.

The challenge is that each has elements of risk that have more in common with late-stage venture capital than typical project finance. It is possible to see through to potential project finance transactions, but it is still early in the lifecycle for a project finance lender.

The project finance market is not set up to take technology risk in any major way, so the early movers in these markets are focused on areas where technology is not a major factor.

The project finance market will take business risk. Thus, the questions project finance lenders are asking about any technology that has been proven are whether the business model makes sense, is it sustainable, and are the elements in place to grow it? How much deal flow is possible if we commit the resources to the market?

The early deals tend to be riskier deals. This is reflected in how a bank will structure them: for example, with less leverage. The deals tend to be at the smaller end of the spectrum which makes them hard to syndicate by bringing in other banks as co-lenders. Bank margins are higher to reflect the additional perceived risk. Some borrowers will have never done project financing before. At the same time, the lender will be looking for a template that is sustainable and scalable.

There are not a lot of project finance lenders that can accept this type of risk or are willing to lend at such an early stage of a developing market. Thus, the universe of potential lenders is small.

Nevertheless, many lenders will try to mitigate the risk by bringing in a couple of other lenders with them.

The loan amounts are often less than $50 million for most such transactions. Any lender playing in this market will want to see an opportunity, by taking development-type risk, to become smarter earlier than the rest of the market and grow with a promising company and the market. Eventually, the higher-cost early-stage debt will be replaced with lower-cost capital as the business model becomes more widely accepted.

Getting Started

Project finance banks see all sorts of deals. Companies that have management teams that understand how to move over time to more of a project finance model come to us before deals are ripe for project financing just to understand what is doable. They want to know what they have to put in place in order to make a project or a portfolio financeable from a project-finance standpoint.

Other management teams come at this from the technology side. Project finance is something with which they are not very familiar. Working with them takes a lot more time for the lender. The scale is often a little too small for the bank market, so lenders will be careful and selective.

The main things on which the lender will focus are technology risk — the project finance market does not take it — and visibility on revenues. It will want a reasonable period of contracted revenues. No one is expecting the equivalent of a 20-year power purchase agreement in these emerging markets, but the longer the revenues can be contracted, the better.

When the residential solar market emerged as a truly bankable market, the issues were initially around consumer credit. For something like storage, the regulatory regime is still being written. One of the challenges in any new market is to figure out what you do not know. Project finance is an exercise in identifying all the risks and then assessing how they can be mitigated or be assigned to other parties in the transaction. A basic rule of thumb in project finance transactions is the person who best understands and is in a position to manage the risk takes it.

Maybe the lender starts with something small like a pilot-scale project where the developer has enough contracted revenue to begin to finance against. Just start putting the pieces together and build over time.

It may be worth a lender's time to do a smaller and less profitable early transaction because it is a good entry point into a broader pipeline of transactions.

Storage

Stem, a battery company, is a good example. It has been one of the early movers in the storage market. It is well capitalized and has brand recognition. It has been working to perfect business models that are financeable, and it is now getting traction with financiers. It announced a deal recently with the Ontario Teachers' Pension Plan to finance shared / *continued page 20*

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exceeded their investments. The fraud affected at least 90 customers in a number of western states.

The lenses were never put in service. They were supposed to hang from towers and concentrate sunlight on a heat-exchange fluid that would then transfer heat to a boiler to produce steam to turn steam turbines.

No electricity was ever produced. Most of the lenses sold were never made or installed. Customers paid $3,500 in theory for each lens, but paid a maximum of $1,050 down with the rest to be paid over 30 years after a five-year lag. The promoters told customers they could calculate tax credits and depreciation on $30,000, and that the lenses would be put out for lease that would earn them $150 a year in rental payments. A government witness said that the lenses had a market value of about $100 each.

The IRS started investigating six years into the marketing efforts in 2012 and, by 2013, was disallowing tax benefits and contacting accountants in an effort to head off more claims.

The trial last 12 days. The government called 25 witnesses. The defendants called none. The case is *United States v. RaPower-3, LLC*.

ZERO EMISSIONS CREDITS were upheld — again.

State plans to keep nuclear power plants running in New York and Illinois by awarding the power plant owners "zero emissions credits" were upheld by two US appeals courts in September.

The credits — called ZECs — have some features in common with renewable energy credits offered under state renewable portfolio standards.

Five independent generators, the Electric Power Supply Association and the Coalition for Competitive Electricity tried to block New York from awarding zero / *continued page 21*

Financing Storage

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savings programs on some of its battery deployments.

The shared savings model is interesting. The battery owner is paid a share of the savings on electricity costs realized by the customer. The challenge for any lender is to figure out how to add value after there is enough experience with the business model to be able to price it properly.

Lenders are trying to crack the code of how to deal with a battery company whose customers are corporations without credit ratings. The battery company may have 10- and 15-year contracts with these customers to share electricity savings from installing a battery. Evaluating the credit risk that the customer will continue to meet its obligations during the contract term is challenging.

Bankers are eager to be first movers in financing energy storage and electric-vehicle charging stations.

Lenders are playing with different tools to try to address this. For example, rating agencies like Moody's and S&P have proprietary models that effectively produce a credit score. Lenders are assessing whether they can finance off such credit scores. Will the broader market accept such proxy ratings as reliable? If so, it will open a much larger market. Maybe a portfolio is the answer. There is risk diversification in aggregating a lot of corporate credits.

When the bank market started lending to residential solar companies, it had to get comfortable with assessing FICO scores. This was something that was very new and, frankly, some banks even today are not particularly comfortable with consumer credit risk in project finance transactions.

The idea was to focus on higher-rated credits, create baskets of risk, and create a portfolio that has some level of diversification that is able to withstand downturns. As a result, these loans continue to perform well. The goal would be to build something like that for corporate credits.

The big picture with storage is that the industry is still waiting to understand how these resources fit into the grid. The Federal Energy Regulatory Commission issued Order No. 841 in February which will help, but there is plenty of work to be done.

Beyond that, the opportunities vary by region. California, New York, Ontario and New Jersey, for example, have introduced incentives to promote standalone storage. The financial community is still getting its head around the standalone business model.

Storage in conjunction with other types of assets is getting more traction quickly. An example is where battery storage is added to a utility-scale solar project. A lender is not particularly concerned about whether that storage is economic as long as the solar project can cover the debt service.

With standalone storage, lenders are still trying to understand the revenue model, the technology and the use cases. Financing becomes easier to the extent there is a contract requiring capacity payments or a reservation charge for use of the storage facility. The financing becomes even more interesting where there are potentially multiple revenue streams and the bank is relying on some contracted and some market-based revenues and, in some cases, shared savings. There is room for creativity in such situations.

Lithium-ion batteries are the name of the game today. There are many other technologies competing for market share. Lithium ion enjoys scale and continues to ramp up. It benefits from the build out of cell production capacity to serve the electric vehicle market. At the moment, it is the most aggressively priced and has the backing of larger industry players.

Having someone like a Samsung or LG stand behind the performance warranty for a lithium-ion battery is a big plus from a project finance standpoint. As we move into other technologies like flow batteries, they tend to be backed by smaller companies. They lack the economies of scale, so they are more expensive. They are farther away as a technology from being ready for project financing, but may gain traction in specialized applications.

What are the necessary predicates to get a storage project financed? One is to have a major battery supplier involved. Another is a 10-year warranty. At this stage in the technology lifecycle, lenders want to lend for a term that is shorter than the warranty. Next is an experienced project manager with a track record. Next is a satisfactory business model. It is easiest to lend against a capacity payment. If the revenue is shared savings or ancillary services payments from the grid for providing things like voltage regulation, it becomes more time consuming to evaluate, and financing costs are likely to be higher.

We have seen scenarios, like with PJM, where the rules of the game changed and some types of technology could deal with it and some could not. Lenders who have gone through that will want to make sure the technology is solid enough to back up the revenue case.

Lenders are pretty aggressive currently. There are more banks chasing deals than there are good projects to finance. Plenty of banks are looking to do a battery deal. A battery transaction with a stable revenue stream should get a significant number of takers. A transaction that relies on revenue from ancillary services will face more of a risk premium, but those are also attracting a number of bids in the current market.

EV Infrastructure

There is a lot going on behind the scenes in the EV charging area. A major push is expected in the United States to build out charging infrastructure. The key questions are what adoption looks like and what is the revenue model.

Some of the basic elements required to do a project financing are starting to emerge.

Electrify America is a Volkswagen initiative that came out of the diesel-emissions settlement. It has made a commitment to deploy $2 billion over 10 years in charging infrastructure.

One of the planned projects is to electrify the interstate highway network. The interstate highways would have a charging station every 50 to 70 miles. This would help address range anxiety that is an impediment currently to wider adoption of electric vehicles.

At the same time, Volkswagen (along with most other automakers) is introducing a series of electric vehicles that can use the charging network.

When a lender starts to look at financing a portfolio of such charging stations, the first question is */ continued page 22*

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emissions credits worth $17.48 a megawatt hour in 2017 and 2018 to owners of nuclear power plants in the state. The value of the credits will be reset after 2018. The program is expected to run 12 years.

The 2d circuit US court of appeals upheld the plan in late September.

The case was a test of whether a state can offer such credits as a supplement to wholesale power prices without running afoul of federal law. Only the Federal Energy Regulatory Commission can set wholesale power rates for electricity sold in interstate markets. States retain the right to regulate retail sales of electricity within their borders.

Three of the six nuclear power plants in New York qualify currently for credits. Others may still qualify in the future. The credits were approved by the New York Public Service Commission in August 2016 in an effort to keep the plants open. Nuclear power accounts for roughly 29% of total New York generating capacity. The state says the nuclear plants are important to limit carbon emissions.

The nuclear plant owners will sell the credits to the New York Research and Energy Development Authority, NYSERDA, at prices established by the New York Public Service Commission. NYSERDA will then resell them to New York utilities on a pro rata basis in proportion to each utility's share of total New York electricity load.

Low natural gas prices are forcing nuclear power plants in parts of the country with competitive power markets to shut down.

The credits represent a significant subsidy on top of what the nuclear plants are being paid currently for their electricity. The generators, who compete with the nuclear plants for a share of wholesale power sales, argued that the program is illegal state interference with the wholesale power market because it will artificially depress wholesale power prices by keeping generators in business who would otherwise have dropped out of the market.

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Financing Storage

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what the revenue looks like. It may be possible to contract with a fleet operator for use of the charging network. Public transit will be an early adopter of electric vehicles. It could be such a user.

The revenue models are still very much in the formative stages. Maybe there is an opportunity to co-locate storage with charging stations. The higher the speed of the chargers, the greater the potential for grid deficiencies that might hamper their deployment. Storage can help.

These are the ideas that are being discussed. The goal is to start configuring business models early with an eye toward something that is project financeable. Maybe the answer is a revenue-stacking model where there is possible revenue not only from the EV charger but also from a battery, and maybe a solar array can be looped in as well.

We may be looking at EV charging as a standalone with the proper types of contractual arrangements, or at multiple technologies bundled together in a hub or a unit in order to create a more certain base revenue stream that is high enough to justify the expense of the bundled equipment.

There are no hard-and-fast models yet. The era where financing required a 20-year PPA to be bankable is fading quickly. As technologies become more distributed and the revenue streams become more diverse, lenders will have to deal with multiple contracts and a mix of fixed and market-based revenues. Such arrangements are likely to become the norm in the future.

The biggest mistake lenders make in new areas is to take on risk that they do not understand fully. New areas take time to develop. Lenders will need to do deep diligence, catalog the risks and identify a finite set that they understand well enough to price and underwrite. ◎

PACE Securitizations

by Patrick Dolan, in New York

Securitizations are becoming a more common technique to raise low-cost debt for energy projects.

To understand securitization structures, take Macy's department store as an example. Macy's issues its own private-label credit cards. Customers use the cards to buy items on credit and pay for them over time.

Macy's can convert the future customer payment streams into current cash. It does so by selling the customer receivables to a bankruptcy-remote special-purpose entity, and that entity issues bonds backed by the receivables.

Macy's makes a true sale of the receivables to the bankruptcy-remote entity so that a Macy's bankruptcy would not prevent the entity continuing to receive the customer payments. The lawyers give a non-consolidation opinion confirming that the special-purpose entity would not be consolidated with Macy's in a Macy's bankruptcy.

Macy's gets cash today. It sells the payment stream to the special-purpose entity, and the bond proceeds come back through that entity to Macy's. The bonds issued by the special-purpose entity are issued at a much lower interest rate than if Macy's were to issue debt directly, because the special-purpose entity has been insulated from Macy's bankruptcy risk and it has an independent director and other required language in its LLC agreement or charter to make it bankruptcy remote.

Historically, securitization has not been an option in the project finance market because, in most project finance deals, you have a single borrower. There is not the diversification of customer risk that you have in more traditional securitization transactions where there may be thousands of customers as in the case of a residential mortgage loan securitization. Nevertheless, people have become more comfortable over the last five to eight years with such securitizations.

Several project finance bond infrastructure securitizations in Latin America are in process now involving government payment receivables.

An investment-grade company has a lot of different financing options. For a sub-investment-grade or non-investment-grade company like Macy's or a special-purpose entity that owns a single project, it is a way to access the capital markets and borrow at a much lower interest rate than if the company issued the debt directly. The debt will be rated. The interest rate will be the same rate that would be charged to an investment-grade borrower.

PACE

A subset of securitizations involves PACE bonds.

PACE stands for Property Assessed Clean Energy. Municipalities borrow and make loans to local residents and businesses to install solar systems and make other energy efficiency improvements. The local homeowners and businesses repay the amounts borrowed through additional property tax payments over time.

PACE has been around since 2012, and PACE bonds have been securitized since around 2014. The first PACE program was in Berkeley, California. Such programs relied initially on a 1918 highway improvements statute in California and then moved to reliance on another law called the Mello-Roos statute.

The bonds issued by the municipality are secured by a lien over the house or building on which the improvements are made. The lien is a first-priority lien in almost all states, so it comes ahead of all other creditor claims to the property other than other property taxes.

The additional assessment is a separate line item on the property tax bill.

The PACE assessment travels with the house or building. Thus, if the house or building is sold, the new owner must continue making the additional property tax payments.

If there is a default on the additional property tax payment, only the defaulted installment of the PACE assessment gets accelerated. Thus, the trustee for bondholders holding the securitized paper cannot accelerate the full remaining payment obligation of a defaulting customer.

PACE borrowings are set up through a master bond indenture where a municipality — typically a county or joint powers authority — issues nonrecourse bonds secured by the assessments. A trustee acts on behalf of the bondholders. The trustee has a right to cause the municipality to initiate a foreclosure against a particular house or business.

The municipality enters into a contract with a program administrator to handle almost everything associated with the PACE program. The program administrator helps the municipality set up the program. In California, this is done through a court proceeding in which local residents and mortgage lenders and other interested parties are given a chance to object and the court eventually issues an order authorizing the program.

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The appeals court disagreed. It called the effect on wholesale power prices “incidental.” It had a hard time seeing any difference between renewable energy credits and ZECs. Both reward production from particular sources rather than insert themselves directly in electricity sales.

FERC has said that states may “grant loans, subsidies or tax credits to particular facilities on environmental or policy grounds,” and even go so far as to order retirement of existing power plants or construction of new ones that are environmentally more friendly, the court said.

“To the extent the ZEC program distorts an efficient wholesale market, it does so by increasing revenues for qualifying nuclear plants, which in turn increases the supply of electricity, which in turn lowers auction clearing prices,” the court said. “But that is (at best) an incidental effect resulting from New York’s regulation of producers . . . . ZECs do not guarantee a certain wholesale price that displaces the NYISO auction price.”

The court also said it could not see how the ZEC program interferes with federal goals.

The case is *Coalition for Competitive Electricity v. Zibelman*.

Meanwhile, the 7th circuit court of appeals upheld a similar program in Illinois in early September.

The plaintiffs have now lost challenges to the ZECs programs in Illinois and New York in both federal district courts and on appeal.

Illinois is expected to award roughly $235 million a year in ZECs to Exelon to help keep open two nuclear power plants in Illinois for 10 years.

The utility has two large nuclear power plants in the state with a combined capacity of about 3,000 megawatts. ZECs are awarded under the Illinois program to any power company that is capable of generating zero-emissions electricity equal to about 16% of what the state retail / continued page 25

PACE

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The program administrator vets potential candidates for loans to make efficiency improvements. It gets the customers signed up. It does the underwriting, approves the contractors who put in solar panels or other improvements, and makes sure the additional property tax assessment and lien are filed in the real estate records.

Securitizations are becoming more common in the project finance market.

The program administrator gets a fee for running the program and usually gets first claim on buying the underlying PACE bonds that are issued. The program administrator aggregates the bonds in a warehouse facility and then securitizes them by issuing a wrap bond against all the paper.

Residential v. Commercial

There are both residential and commercial PACE programs. The residential PACE market is much more active, but in residential PACE, the program administrator does not usually try to get consent from any existing holder of a mortgage on the property. In commercial PACE, by statute or just by practice, the program administrators always get the consent from any first-mortgage lender for the property tax assessment to take priority.

The typical PACE assessment on a residential property is about $18,000, and it is considered too small to bother with lining up consents from mortgage lenders. On the commercial side, the assessments typically start at $1 million and can be multi-million dollar assessments. Even where mortgage lender consent is not required by statute, the litigation risk and the dollars involved are too big not to get consent.

There is an 800-pound gorilla in the room on the residential side, which is the Federal Housing Finance Agency, which is the overseer of Fannie Mae and Freddie Mac. Fannie and Freddie have objected since the outset of residential PACE to any first lien for PACE lenders, and they have told their correspondent lenders over the years not to buy any mortgage loans on properties that have residential PACE assessments on them.

We understand anecdotally that not all correspondent lenders follow that guidance, so some do buy mortgage loans with PACE assessments on the properties.

The FHFA takes the position that a PACE assessment coming after the fact changes the bargain for the mortgage lender. The PACE assessment takes priority over the mortgage lien. The FHFA historically has also questioned whether solar systems and other energy efficiency improvements actually improve the value of the property and to what extent they reduce energy costs over time.

The FHFA has also heard from real estate brokers in California that PACE liens place a cloud on the title of the property when the homeowner goes to sell his or her house. It says the homeowner will need to pay off the remaining property tax assessment or else he or she will be paid less for the house.

The FHFA has litigated issues like condo association liens in Nevada, but it has never litigated the issue whether a PACE assessment trumps the mortgage lender's lien. Thus, to date, the first lien for the PACE lender has always been respected.

One of the issues that is covered by the court order when a PACE program is first established in California is the constitutionality of the arrangement: whether there is an impermissible taking of a property right belonging to the mortgage holder. The court order blesses the indenture, the program administration agreement, and the form of assessment contract between the homeowner and the county and the program administrator. The FHFA has not challenged these court orders.

Market Activity

For the last four years, California has been the market leader for residential PACE programs. Florida is also a significant market, but PACE was slower to get traction there after the mortgage bankers association litigated over the first-lien issue. Missouri has seen some activity on the residential side.

Connecticut is the leading state for commercial PACE programs. The Connecticut Green Bank made an effort to educate both developers and local first-mortgage lenders about the benefits of PACE and how it can improve the value of commercial buildings.

Commercial PACE activity has also been picking up in places like California and Texas. Commercial PACE has been slower to take hold because commercial developers tend to have other financing options and their first-mortgage lenders, who hold the liens on the commercial buildings, must be convinced to consent to a lien to secure the PACE assessment.

Many first-mortgage lenders do not want to hire lawyers to review consents, so it can be a slow process to line up consents. However, the market is gaining momentum. DBRS did the first 144A publicly rated C-PACE transaction in August 2018. Twain Financial Partners did a section 4(a)(2) private placement a few weeks before that was not publicly rated. At the end of 2017, Green Works Lending did a section 4(a)(2) private placement of C-PACE bonds that was also not publicly rated.

The three C-PACE securitizations done so far have each raised between $75 and $105 million. Contrast that to PACE offerings in the residential sector, which have amounted to about $4 billion since 2014. All of the residential deals involved publicly rated debt issued under Rule 144A.

California at the end of last year enacted some consumer-focused statutes. PACE originators took the position in the past that PACE loans are not consumer loans and do not have to comply with consumer lending laws. That changed last year when California enacted two bills focused on building up the federal and state consumer protections, and then President Trump earlier this year signed into law a bill that directs the federal Consumer Financial Protection Bureau to focus on consumer protections in residential PACE programs, thus subjecting PACE originators of residential loans for the first time to federal regulation.

Ironically, when Obama appointee Richard Cordray was head of the CFPB, he took the position that / continued page 26

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load was in 2014. Illinois utilities must enter into 10-year contracts to buy ZECs from facilities that are awarded the credits.

The price is $16.50 a megawatt hour, which Illinois set based on a federal working group's calculation of the social cost of carbon emissions. The price per megawatt hour falls if a "market price index" exceeds $31.40 a megawatt hour. Illinois derives the index from the annual average electricity prices set in PJM auctions and two state energy markets.

The plaintiffs argued that the price adjustment aspect steps across a line into regulating wholesale electricity prices.

The appeals court asked FERC its view. FERC said the program does not interfere with interstate electricity auctions and is not otherwise preempted by federal law.

The court said the Illinois program has only an indirect effect on wholesale prices by keeping nuclear power plants that might otherwise shut operating. "A larger supply of electricity means a lower market-clearing price, holding demand constant," the court said, but a "state policy that affects price only by increasing the quantity of power available for sale is not preempted by federal law."

The court also rejected an argument that the Illinois program violates the US constitution by interfering with interstate commerce.

The court said the state was merely regulating inside Illinois. "All carbon-emitting plants in Illinois need to buy credits. The subsidy's recipients are in Illinois; so are the payors."

The Illinois case is E*lectric Power Supply Association v. Anthony M. Star.*

Output from nuclear power plants was up 4.05% during the first half of 2018 compared to the same period in 2017, according to the latest "Monthly Energy Review" released by the US Energy Information Administration in late September.

Output from non-hydro renewables was up 7.04% during the same period. Fossil fuels output increased by 8.8%. Carbon emissions were up by 3.04%. / continued page 27

PACE

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consumer PACE was something the states could deal with without the need for federal intervention. Originators now have an obligation to determine whether consumer PACE borrowers have the ability to repay the assessment. Consumers have a right of rescission. A lot more disclosure is required to consumers. Residential PACE originations in California are down significantly this year.

Senior tranches of PACE bond securitizations are often rated AAA.

It is generally not worth the transaction costs to do a C-PACE securitization until the bond amount is at least $75 million. Deals on the residential side tend to be in the $300 million range. ◎

Construction Stopped Despite Having Permits

by Sue Cowell, in Washington

Two courts stopped construction of natural gas pipelines in the last few months due to problems with permits.

The cases are a reminder to project developers and lenders to be more careful when assessing whether projects not only have all the permits, but also whether the permits are still open to challenge, or when evaluating the any pending litigation before the start of construction. This is especially important as agencies are being pressured to speed up their reviews and issue permits more quickly.

Another court found problems with permits, but has not stopped construction of a natural gas pipeline in New Jersey.

All three projects had been issued certificates of public convenience and necessity by the Federal Energy Regulatory Commission. The problems were with permits issued by other federal or state agencies. The certificates of public convenience and necessity were contingent on the projects receiving all the other required clearances.

Transcontinental Pipeline

A US court of appeals found problems in early September in a case involving the Transcontinental Gas pipeline with a freshwater wetlands individual permit and water quality certificate and a dewatering permit issued by the New Jersey Department of Environmental Protection (NJDEP).

pipeline had all the required permits, but challenges to the permits were filed with the NJDEP after the permits were issued. The NJDEP declined to consider the challenges on grounds that the US court of appeals has exclusive jurisdiction to review permits for interstate natural gas pipelines.

The court disagreed that it has exclusive jurisdiction. The federal Natural Gas Act gives the US court of appeals for the circuit where the pipeline is located original and exclusive jurisdiction over civil suits to review actions taken by state agencies pursuant to delegated authority under federal laws. The court said a request for an administrative hearing to decide whether a permit was properly issued is not a such a civil action. The court sent the case back to the NJDEP.

So far, no request has been made to stop construction.

Atlantic Coast Pipeline

The Atlantic Coast pipeline, which received its FERC certificate of public convenience and necessity on October 13, 2017, ran into trouble with other permits and had to stop work in August 2018 after construction was already underway.

The 600-mile pipeline would run between West Virginia and eastern Virginia and North Carolina and traverses the Blue Ridge mountains. Some construction activities had been underway for more nine months when the developer had to stop work.

Environmental groups challenged two other federal permits that were issued to the pipeline. One is an incidental "take" permit issued by the US Fish and Wildlife Service (USFWS) that authorizes the "taking" — meaning the harassing, harming or killing — of protected species as long as it does not jeopardize the continued existence of any protected species or destroy or adversely modify a critical habitat of a protected species. They also challenged a right of way granted by the National Park Service to allow the pipeline to pass underneath a scenic road called the Blue Ridge Parkway that runs through the mountains.

A US court of appeals held in August that the agencies acted "arbitrarily and capriciously" when they approved the take permit and right of way.

It is unlawful under the federal Endangered Species Act to "take" any federally endangered or threatened species. Federal agencies must consult with the USFWS before taking any action that may affect any federally-protected species, species proposed to be federally-protected, or any designated critical habitat of protected species or a habitat that is proposed to be designated for protection.

The USFWS identified five threatened or endangered species that may be affected by the Atlantic Coast pipeline, but the court said the analysis did not go far enough. Instead of setting numbers of species that could be taken, the agency used a habitat surrogate. In other words, the USFWS focused on effects on habitats where protected species live as a proxy how many such species might be "taken," but without satisfying the regulatory requirements for using habitat as a surrogate.

The court also took issue with the right of way issued by the National Park Service because the agency failed to explain how crossing the Blue Ridge Parkway was not inconsistent with the purposes of the Parkway and the overall national park system.

Four days after the court decision, FERC ordered work halted along the entire pipeline route, except for that work that the USFWS and National Park Service / *continued page 28*

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CRYPTOCURRENCY use risks triggering unwanted tax consequences.

Kevin Brady (R-Texas), chairman of the House tax-writing committee, and four other committee Republicans asked the IRS commissioner in a September 19 letter when the agency expects to issue more guidance on the US tax treatment of cryptocurrencies and what he expects that guidance to say.

The IRS warned taxpayers in 2014 that the US treats cryptocurrencies as "property" so that anyone spending or selling a cryptocurrency will be treated as having sold an asset and must report the gain or loss for tax purposes.

The letter said the IRS has used John Doe summonses to seek the records of half a million Americans who held cryptocurrencies between 2013 and 2015. The IRS issued a separate summons to the cryptocurrency exchange Coinbase Inc. in 2016 to gather records on virtual currency trades. The IRS launched a campaign in July to ensure that large businesses report any cryptocurrency gains.

Brady and the other Republicans said they are "concerned that the IRS is seeking to enforce guidance that does not adequately advise taxpayers of their tax obligations when using virtual currencies." For more detail on the US tax treatment, see "Cryptocurrencies and Taxes" in the August 2018 *NewsWire*. The only US guidance to date is in IRS Notice 2014-21.

Other countries are also struggling to come up with guidelines. The Organization for Economic Cooperation and Development, an organization of 34 developed countries, is in the preliminary stage of working through cryptocurrency tax questions and may make recommendations as early as December.

Canada said in 2013 that it would treat virtual currencies as commodities like gold and silver.

The US Commodities Futures Trading Commission treats then as commodities covered by the Commodity Exchange Act. The US Securities and Exchange Commission is wrestling with whether / *continued page 29*

Problem Permits

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determined were needed to stabilize the right of way and work areas. FERC staff explained that while there was no reason to expect the USFWS and National Park Service would be unable to comply with the court's order and at some point issue approvals, it was hard to predict when, or whether such approvals would be issued for the same route.

As a result, FERC staff said, "allowing continued construction poses the threat of expending substantial resources and substantially disturbing the environment by constructing facilities that ultimately might have to be relocated or abandoned."

The National Park Service and USFWS moved quickly. The National Park Service reissued the right-of-way permit and the USFWS issued a modified biological opinion with a modified incidental take statement a little over four weeks after the FERC order to stop work. FERC lifted the stop-work order three days later.

However, the pipeline is not in the clear. After FERC issued the stop-work order, the appeals court blocked reliance on a special use permit issued by the US Forest Service. This led environmental groups in late September to ask FERC reinstate the stop-work order since the project no longer has all of its permits. Opponents have also asked the US appeals court to review the FERC approval of the project.

Mountain Valley Pipeline

FERC temporarily ordered work halted on the approximately 303.5-mile Mountain Valley pipeline between West Virginia and Virginia before lifting the stop-work order about four weeks later. A US appeals court then blocked work in early October.

The project received a certificate of public convenience and necessity on October 13, 2017. Opponents challenged a 3.6-mile right of way granted by the Bureau of Land Management over federal land and amendments that the US Forest Service made to the Jefferson National Forest resource management plan to accommodate the pipeline.

A US court of appeals set aside the right of way on July 27 because of potential problems under the Mineral Leasing Act. The Mineral Leasing Act requires the Bureau of Land Management to try to get all persons needing authority to cross federal land to use the same right of way to the extent practical in order to minimize environmental impacts and the proliferation of separate rights-of-way across federal land.

The court said that BLM failed in this case to show that use of existing rights of way was impractical before granting the pipeline an alternate route.

FERC considered various alternative routes in an environmental impact statement it prepared before granting the pipeline a certificate of public convenience and necessity. BLM adopted FERC's environmental impact statement, but the court said the Mineral Leasing Act requires more of BLM. The FERC environmental impact statement weighed the environmental costs of different pipeline routes and whether the routes were economically feasible. BLM never made a separate determination that requiring the pipeline to use an existing right of way was impractical. The court sent the project back to BLM for such a finding.

The court also set aside the US Forest Service decision to amend the Jefferson National Forest land resource management plan on grounds that the Forest Service had failed to comply with the National Environmental Policy Act and the National Forest Management Act.

The National Environmental Policy Act requires federal agencies to evaluate the environmental impacts of their actions. To do this, agencies prepare an

Three recent gas pipeline cases are a reminder that permit challenges can continue after projects are under construction.

environmental analysis such as an environmental impact statement. When multiple federal agencies are involved on a project, the lead agency (in this case FERC) prepares the environmental impact statement that the other agencies may adopt, provided that such agencies independently review the statement and determine that their comments have been addressed. The Forest Service had expressed concerns in comments to the draft environmental impact statement about erosion and sediment impacts, but did not explain when it amended the Jefferson National Forest resource management plan why it was no longer concerned about these issues after the environmental impact statement failed to address them. The court directed the Forest Service to explain its decision in light of its earlier concerns.

FERC issued a stop-work order for construction of all parts of the project, except for work necessary to stabilize the right of way and work areas. Although FERC said it had no reason to suspect that BLM and the Forest Service would ultimately be unable to provide approvals for the project, it was possible that such approvals could be for alternate routes.

FERC released the project to resume work on August 29 after an interim BLM assessment of other potential routes that still favored the original route and in view of the fact that much of the route had already been cleared and graded.

However, the appeals court set aside another of the permits for the project in early October — this time the US Army Corps of Engineers nationwide permit 12 that lets pipelines advance even though they cross waterways. The court said the US Army Corps lacked authority to ignore a West Virginia permitting restriction in such situations. Since it no longer had permission for the water crossing, construction had to stop. The work can resume once the Army Corps issues a permit specifically authorizing such a crossing for this project.

This work will have to remain stopped until the US Army Corps of Engineers issues a permit for this work. ◎

to treat initial coin offerings that are being used to raise capital to build out blockchain-based trading platforms as "securities" that would subject such offerings to regulation.

A US district court in New York upheld a criminal indictment in September for securities fraud involving sales of cryptocurrency tokens in an initial coin offering in a case called *US v. Zaslavskiy*.

For more on initial coin offerings, see "Anatomy of an ICO" in the April 2018 *NewsWire*. For a global guide to legal and regulatory issues surrounding cryptocurrencies, see "Deciphering Cryptocurrencies" at http://www.nortonrosefulbright.com/knowledge/technical-resources/blockchain/deciphering-cryptocurrencies/.

Global cryptocurrency holdings are worth around $211 billion. Bitcoin has fallen around 50% in value and ether has fallen around 70% from peaks in late 2017.

Governments are concerned that the anonymity of cryptocurrencies allows them to be used for a range of illegal activities, including drug trades and money laundering.

REPATRIATED PROFITS are being used mainly for share buybacks and debt repayments.

The US Congress took steps last December to encourage US companies to bring home the more than $2 trillion in earnings parked in offshore holding companies for reinvestment in the United States.

Tax reforms last December moved the US closer to a territorial tax system where US companies are taxed only on income from US sources, thus giving companies less reason to keep earnings parked offshore. At the same time, the tax reforms subjected the accumulated untaxed earnings then sitting offshore to US tax through a deemed repatriation. Companies can spread the taxes on them over eight years starting in 2017.

JPMorgan Chase & Co. reported in September that 95% of earnings actually

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California Update

by Jim Berger, in Los Angeles

Two new laws enacted in September will have a major effect on the California energy market.

100% Clean Energy

Senate Bill 100 will require all electricity in California to come from clean energy by 2045, and it increases the existing 2030 target from 50% to 60%. Governor Jerry Brown signed the measure on September 10.

"Clean energy" for this purpose is not yet defined. It will include "eligible renewable energy resources," which presumably would include everything that is eligible under current law: biodiesel, biomass, bio-methane, fuel cells with renewable fuels, geothermal, certain kinds of hydroelectricity, municipal solid waste, ocean wave, ocean thermal, solar, tidal current and wind. It will also include "zero-carbon resources," which are also not defined. This could include nuclear energy, but it seems unlikely because California is shutting down its last nuclear plant by 2025.

The interim goals along the road to 100% clean energy are 44% clean energy by 2024, 52% by 2027 and 60% by 2030. The state is currently at about 44% clean energy, including 15% from large hydroelectric projects and 29% from renewables.

The law requires retail electricity sellers to procure at least the required percentages from clean energy sources. Municipal utilities must reach the same percentages, but they can do so by buying clean energy credits.

The real goal is to reduce carbon emissions that contribute to global warming. The electricity sector is responsible for only 16% of California carbon emissions, while the transportation sector is responsible for 41%, the industrial sector for 23%, agriculture for 8%, residential energy use for 7% and commercial energy use for 5%.

To address all of these other sectors, which account for 84% of carbon emissions, Governor Brown issued Executive Order B-55-18, which sets a goal to achieve carbon neutrality by 2045 and to maintain net negative emissions thereafter.

Executive Order B-55-18, if fully implemented, could have a larger effect than SB 100 because it will affect all sectors of the economy and not just electricity generation. It is likely to tie disparate sectors of the economy together. For example, certain industrial sectors may not be able to eliminate carbon emissions completely; they will end up making transfer payments to other sectors, such as agriculture or forestry, that do.

The executive order directs the California Air Resources Board, or CARB, to come up with a way to track progress and to work with state agencies to ensure that future "scoping plans" recommend measures to achieve the goal. Scoping plans are plans, updated every five years, that focus on how each agency can reduce greenhouse gas emissions.

To have negative carbon emissions after 2045, more carbon dioxide will have to be sucked out of the air than is released into the air. The executive order directs CARB, the California Natural Resources Agency, the California Environmental Protection Agency and the California Department of Food and Agriculture to set sequestration targets in the "natural and working lands climate change implementation plan," which is a plan that state agencies are developing, among other things, to find more ways to sequester carbon underground.

Transforming transportation — which accounts for the largest source of carbon emissions — to reduce emissions could significantly affect the power industry. The most likely way to reduce carbon emissions is to electrify transportation. However, doing this would significantly increase electricity demand, further increasing demand for clean sources of electricity.

One measure that failed to become law is AB 813, which was a bill that would have converted the California Independent System Operator, which operates the California electricity grid, into a regional transmission organization. (For more details about AB 813, see the "California Update" in the August 2018 *NewsWire*). The lack of a regional grid could make it harder to reach the other goals the state has set. Brown has supported the measure, but the bill failed to make it through the upper house of the state legislature after passing the lower house in August.

Wildfires

Senate Bill 901 limits the damages for which the three investor-owned utilities can be held liable on account of wildfires that are started by electrical equipment belonging to the utilities. However it did not eliminate the doctrine of inverse condemnation as both the utilities and the governor had wanted. Inverse condemnation makes a utility liable for all fire damages where utility equipment contributed to a fire, regardless of whether the utility was at fault.

The bill has been widely seen as a rescue for Pacific Gas & Electric, which serves northern California, to avoid pushing the utility into bankruptcy.

PG&E may be found liable for $15 billion or more in damages tied to wildfires in 2017. No one wants to see PG&E pushed again into bankruptcy. The effects of its last bankruptcy in 2001 during the California energy crisis were felt for years. The state also needs a healthy PG&E to help meet its aggressive clean energy goals.

The utilities themselves have also suffered destruction of power lines, utility poles and substations.

The new law is not a model of clarity, and significant questions remain that will have to be answered by the California Public Utilities Commission, or CPUC, as it implements the provisions.

An initial issue is that the bill addresses wildfires that started in 2017 and wildfires that start in 2019 (and after), but does not address the 2018 wildfires. The legislature will have to deal with the effects of the 2018 wildfires next year.

For the 2019 wildfires, the CPUC may allow the utilities to increase rates to recover costs if the costs are just and reasonable, after considering the utility's conduct. In evaluating the reasonableness of costs, the CPUC is supposed to consider 12 factors, including the nature and severity of the utility's conduct, whether fire warning signs were ignored, whether the utility failed to operate and maintain assets in a reasonable manner and to what extent the fires were caused by circumstances beyond the utility's control.

The CPUC has to go through a similar analysis for costs tied to the 2017 wildfires and determine whether the costs are just and reasonable. The law implies that only just and reasonable costs are recoverable from ratepayers.

The law creates a "stress test." The test is run once a utility applies to recover costs from a 2017 wildfire. The test is not a pass-or-fail type of test, but rather an effort to measure the amount of wildfire costs the utility can bear before having to pass costs through to ratepayers. The CPUC cannot allow a utility to start passing costs to ratepayers until the utility has absorbed all it is able.

Costs that will be borne by ratepayers may be recovered from ratepayers over time through a surcharge added to utility bills. The utilities can seek a financing order from the CPUC that would allow them to borrow against the future revenue stream from the surcharges.

A utility may also seek a financing order to cover costs of a 2019 wildfire.

Typically, utilities have rate cases before the CPUC once a year. It is conceivable that PG&E will file to recover its 2017 wildfire costs outside of the ordinary course */ continued page 32*

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repatriated to date by the 15 US firms with the largest offshore cash holdings were used to buy back shares and repay debt. It analyzed Federal Reserve Board data collected from financial reports.

JPMorgan estimates that 20% to 25% of the offshore cash will be brought back in the near term. It expects the boost this has given to US stock and bond prices to slow in the last half of 2018.

LANDFILL GAS TAX CREDITS were denied.

A US appeals court denied tax credits in August that tax equity investors in two trusts claimed on gas produced at 19 landfills during the period 2005 through 2007.

The United States allowed tax credits to be claimed until recently by producers of "nonconventional" fuels. The credits could be claimed for producing gas from biomass, geopressured brine, Devonian shale, coal seams or tight formations, synthetic fuel from coal, or oil from shale or tar sands. The credits were originally in section 29 of the US tax code. They were moved in 2005 to section 45K.

Credits could be claimed for the first 10 years after the well or other equipment used to produce the fuel was first put into service. It had to be in service by June 1998.

Resource Technology Corporation sold the rights to tap into gas from decomposing garbage at 19 landfills to two trusts and then signed contracts to operate the landfill gas wells for the trusts and to buy the gas.

It ended up flaring the gas or releasing it into the atmosphere.

The IRS disallowed the credits on grounds that Congress intended that the gas would be put to use as fuel. The US appeals court agreed with the IRS in August. The US Tax Court had come to the same conclusion earlier.

The Tax Court had also found fault with the records the trusts produced to show how much gas they produced. It said there were errors rendering the records */ continued page 33*

California

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through an additional rate case. The California fire department has determined that PG&E was at fault for 12 of the October 2017 wildfires. It has not yet determined the cause of others. It will take time for the final tally of PG&E's liability to be determined. When PG&E files to recover costs, it will have to bring data and consultants to prove what it can pay under the stress test. Ratepayer advocates will argue that PG&E can pay significantly more. The CPUC will have to sort through it all, as it tries to apply the unclear, and at times contradictory, language in SB 901. ◎

Environmental Update

California became one of two US states in September to require all electricity supplied in the state to come from renewable or other carbon-free sources. California set a goal of reaching 100% clean energy by 2045.

The only other state with a similar goal currently is Hawaii.

California Governor Jerry Brown said the action was part of the state's commitment to honoring the goals in the global Paris agreement on climate change. The United States gave formal notice in 2017 that it is withdrawing from the pact over concern about the potential cost to the US economy, becoming the only nation to reject the climate change accord. Brown said, "We are going to meet the Paris agreement and we're going to continue down that path to transition our economy to zero carbon emissions."

For more details about the California actions, see the "California Update" in this issue.

The ability of both California and Hawaii to reach 100% clean energy will require battery costs to plunge over time.

Earlier this year, California became the first state to require solar rooftop panels on nearly all new homes.

Vapor Intrusion

For the first time ever, the US Environmental Protection Agency added a contaminated site to the Superfund national priorities list because of vapor intrusion.

Vapor intrusion is the release of volatile chemical vapors from contaminated soil into buildings above ground. It can occur when vapors filter through cracks in the building foundation, dirt floors, utility line openings or other pathways.

An Obama-era EPA rule that went into effect in 2017 added subsurface intrusion to the hazard ranking system that is used to score whether a contaminated property gets listed as a Superfund site.

While the determination to add a site to the Superfund list based solely on vapor intrusion is likely to remain rare, properties with less extensive subsurface intrusion risk are regularly addressed through the Resource Conservation and Recovery Act or under state environmental regulations.

Developers and real estate buyers should be ready to assess potential risks from vapor intrusion before completing a transaction as part of the standard diligence. There are tens of thousands of sites in the United States where past releases of chlorinated solvents or petroleum hydrocarbons could pose a risk of vapor intrusion, even if the property underwent investigation or an incomplete remediation earlier. Even sites that reached regulatory site closure could be reopened under certain circumstances where some contamination remains. In addition, the threat of toxic tort lawsuits alleging vapor intrusion from groundwater that contaminates neighboring properties has become a cottage industry in the plaintiffs' bar.

For vapor intrusion to be of concern, the vapors have both to migrate into buildings and contaminate indoor air to such a degree that human health is affected.

EPA announced the vapor intrusion Superfund listing on September 11. It rejected industry concerns that it would set an adverse precedent by sidestepping standard practice for evaluating vapor intrusion sites. Critics argue that EPA was required to consider the use of permanent vapor mitigation systems in scoring sites for inclusion on the Superfund list and that EPA failed to do so.

EPA proposed in June to amend a list of practices buyers are supposed to use before buying property to assess the environmental risk from prior ownership and use. By going through this checklist, a buyer can limit its potential liability under the Superfund law for the cost to clean up past contamination under certain circumstances. The June amendments added the possibility that vapor intrusion could contaminate indoor air as another item to check.

Stormwater

A federal judge in California ruled that the EPA must either issue Clean Water Act permits for individual properties authorizing the discharge of pollutants in its stormwater, called "NPDES" permits, or prevent the property owners from discharging any polluted stormwater offsite into receiving watersheds.

The judge ruled in early August that, once EPA finds that a property's stormwater discharges "cause or contribute to violations of water quality standards," the Clean Water Act gives regulators no choice but to limit those releases. In so doing, the court rejected EPA's claim that it has discretion to address the pollution through methods other than stormwater permits.

EPA has authority under section 402(p)(2)(e) of the Clean Water Act to issue permits for currently unpermitted sites where it determines that runoff "contributes to a violation of a water quality standard or is a significant contributor of pollutants" to protected waters. This is called residual designation authority.

Environmental groups brought a number of cases against EPA after the agency — including during the Obama administration — rejected petitions to issue new stormwater permits under its residual designation authority.

If other courts follow the logic of this case, EPA and states with Clean Water Act authority could be required to consider stormwater permits even where regulators would otherwise prefer alternative strategies for remedying water quality issues.

The court rejected the argument that other strategies could replace stormwater permits, even if the same qualitative results were achieved. The court said the EPA has only two choices: issue a permit or ban all unpermitted stormwater releases.

The decision was in *Los Angeles Waterkeeper v. Pruitt*.

Cooling Water

Environmental groups have asked a federal appeals court to clarify or revisit a decision upholding the current EPA rules for cooling water intake structures.

The rules in question set technological standards for water cooling systems used by power plants and factories.

The appeals court sided with EPA in late July.

The Clean Water Act requires EPA to set "best available technology" standards to minimize adverse environmental impacts from cooling water intake structures that draw water for cooling purposes and later discharge heated water back into lakes and rivers. EPA rules in this area are supposed to reduce the potential harm to fish and other aquatic organisms from hot water and prevent them from being sucked through the intake structures or pulled up against mesh filters.

Existing rules require use of closed-cycle cooling technology for new facilities that allows reuse of the water after it has time to cool. However, this is not required for existing facilities.

EPA and states use five mandatory and six discretionary

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unreliable. It was also not convinced that the trusts owned the gas they claimed to have produced from four landfills where the rights to remove gas had either expired or were unproven.

The case is *Green Gas Delaware Statutory Trust v. Commissioner.*

THE FOREIGN CORRUPT PRACTICES ACT may not be used to prosecute an individual with no ties to the United States.

A US appeals court blocked prosecution in late August of a British former Ahlstom executive whom US authorities say was involved in hiring two consultants with knowledge that the consultants would use part of what they were paid to bribe Indonesian officials to help secure a $118 million power contract for Ahlstom.

The executive was working for Ahlstom at the time in Paris.

The US says he approved hiring the consultants and knew that part of what they were paid would be used for bribes.

He had no link to the United States.

US prosecutors say several parts of the scheme were executed in the United States. Several Ahlstom executives attended meetings in the US about the scheme and made calls and sent emails about it while on US soil. The bribes were paid from Ahlstom bank accounts in the US and went into a US bank account of one of the consultants.

The Foreign Corrupt Practices Act is a 1977 US law that makes it a crime to offer anything of value to an official of a foreign government, political party or public international organization in an effort to win or retain business or secure any improper advantage.

Even if a crime can be proven, US prosecutors can charge a foreigner only if they can show that he committed the crime while present in the United States while working as an agent of a US company or of a foreign company whose securities are traded on a US

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factors to make site-specific determinations of what is the best available technology to avoid sucking aquatic organisms into cooling-water intake structures, a harm known as entrainment. Becoming trapped against a mesh filter is called impingement. The current rules allow alternative technologies other than the "best available" if site specific conditions favor them.

Environmental groups want EPA to set a single national standard rather than make decisions on a site-by-site basis. They argued that the current approach gives more discretion to regulators than the Clean Water Act allows. The court disagreed.

The environmental groups asked in early September for a clarification or reheating.

They are also unhappy with the manner in which EPA consults with the US Fish and Wildlife Service and the National Marine Fisheries Service about potential harm to endangered species before issuing cooling-water intake permits. They want the court to address whether the government must follow the recommendations that come out of that process.

They also want the federal government to object to state-issued permits that fail to satisfy what the Fish and Wildlife and National Marine Fisheries recommend.

The case is *Cooling Water Intake Structure v. EPA*. It is pending in the 2d circuit, which covers New York, Connecticut and Vermont.

Affordable Clean Power Plan

EPA proposed comprehensive changes to federal regulation of greenhouse gas emissions from power plants in mid-August.

The changes replace the Clean Power Plan that the Obama administration proposed in 2016. The Trump administration says the new plan should be finalized in early 2019.

The Clean Power Plan would have set limits on greenhouse gas emissions from existing power plants, but implementation was blocked by the US Supreme Court, and the plan never took effect. EPA moved formally to withdraw it in October 2017, and the Trump Administration later proposed its repeal.

The new plan does not set specific emissions targets for states to meet. Instead, states would set their own emissions reduction targets, subject to EPA review and approval.

States would still have to submit plans to address certain greenhouse gas emissions, but the plans would be limited to emissions reduction measures that can be applied to individual power plants and not on a sector-wide basis.

Unlike under the Clean Power Plan, states will no longer have to consider whether to impose emissions reductions beyond a plant's fence line, such as taking steps to increase renewable energy capacity, making downstream energy efficiency improvements, or participating in regional emissions trading programs.

The Clean Power Plan allowed states to consider trading emissions allowances both within and across state lines as a way to identify the cheapest compliance options. EPA now says that the federal government lacks the authority to require states to consider such trading and other off-site options.

States would have autonomy to determine how to regulate greenhouse gas emissions from coal plants on a plant-by-plant basis through heat-rate efficiency improvements. Instead of working to achieve overall emissions cuts, states would now choose from a list of candidate technologies to improve heat-rate efficiency at power plants and require implementation of improved operating and maintenance practices at the plant level.

EPA acknowledged that the proposed plan is expected to "increase emissions of carbon dioxide" and "increase the level of emissions of certain pollutants in the atmosphere that adversely affect human health," as compared to the Clean Power Plan. Tables in the 289-page report issued by EPA to support the new plan appear to show that the plan would cause between 470 to 1,400 additional premature deaths annually by 2030 due to comparatively higher emissions of greenhouse gases and other air pollutants.

EPA points to significant decreases in compliance costs and relief for coal-fired power plants.

Where the Clean Power Plan was intended to drive renewable

The ability to California and Hawaii to reach 100% renewables targets will require battery costs to plunge over time.

and clean energy development, the new plan has as one of its goals to try to rescue coal plants from closing. The new legal interpretation that the federal government can only order actions within the fence line of a plant could backfire under a subsequent administration that is more concerned about climate change. It could lead to plants being required to take more drastic technological steps at the plant level if emissions reduction goals increase instead of being able to avail themselves of cheaper measures that could be taken beyond the fence line.

New Source Review

The proposed replacement for the Clean Power Plan would also mean that new source permits would be required in fewer cases when constructing new or expanded conventional power plants.

The new source rules determine whether particular modifications to existing power plants trigger new permitting requirements that force compliance with the latest pollution control standards, a process intended to prevent areas that meet air quality standards from backsliding.

Existing regulations require permitting for plant modifications that significantly increase the facility's annual emissions, while the proposed rule change would allow overall emissions to increase without triggering a permit review if a facility's maximum hourly emissions rate remains the same.

EPA is proposing two alternative ways to measure emissions increases on an hourly basis. States would have the option to choose. One of the approaches is more favorable to coal plants.

Leaked documents show that EPA was weighing whether it should regulate greenhouse gas emissions from power plants at all. In the end, the agency decided not to solicit comments on that question.

While EPA took the unusual step of combining changes to two different power plant regulations under one new rule — namely the standards for regulating greenhouse gas emissions and the new source permitting requirements — EPA included language that would legally separate the air pollution permitting revisions from the underlying carbon dioxide standards. In other words, one provision may be spared if a court strikes down the other.

Science

EPA will reportedly eliminate its office of the science advisor, a high-ranking position created to / continued page 36

exchange or over-the-counter market or are widely held in the United States.

The appeals court said prosecutors would have to show that the Paris-based executive acted as an agent of the Ahlstom US subsidiary. It is not possible to charge him as an accomplice or co-conspirator of others who are covered by the statute.

The case is *United States v. Lawrence Hoskins.*

Separately, the Brazilian petroleum company Petrobras agreed in late September to pay $853 million to settle FCPA violations.

The US Justice Department said in a statement: "Executives at the highest levels of Petrobras — including members of its executive board of directors — facilitated the payment of hundreds of millions of dollars in bribes to Brazilian politicians and political parties and then cooked the books to conceal the bribe payments from investors and regulators."

The Foreign Corrupt Practices Act has an accounting standards section that requires companies to keep books and records "which, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets" of the company. Companies are also required to maintain internal controls that provide reasonable assurance against illegal payments and to run internal checks at "reasonable intervals."

The US Justice Department and Securities and Exchange Commission will keep only 10% of the money. The rest will go to the Brazilian government.

Petrobras shares are traded on the New York Stock Exchange.

— contributed by Keith Martin in Washington

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advise the EPA administrator on the scientific research underpinning environmental and health regulations.

The change would demote the position several levels down so that it is no longer a direct report to the administrator.

EPA spokespersons said the agency decided to combine offices with similar functions and eliminate redundancies.

Last year, EPA scaled back two scientific panels advising the agency on public health rules by barring academic researchers from joining the panels. EPA is also proposing to limit the types of scientific research that officials can take into account when writing new public health policies.

NEPA

A federal judge in Montana ordered the US Bureau of Land Management to review how allowing use of Powder River Basin coal affects US greenhouse gas emissions.

Various plaintiffs are suing BLM to prevent the agency from leasing government land to coal companies to mine coal.

The court determined that the National Environmental Policy Act, or NEPA, requires consideration of the downstream impacts from agency management decisions.

The judge ordered BLM to complete a new NEPA analysis by November 29, 2019. He declined to prohibit any leasing or to overturn existing resource management plans in the meantime.

This is the second court to require downstream greenhouse gas emissions impacts analysis under NEPA. Last year, a US court of appeals ordered the Federal Energy Regulatory Commission to consider such impacts before authorizing construction of a pipeline in the southeast.

The case is *Western Organization of Resource Councils v. BLM*. ◎

— contributed by Andrew Skroback in New York and Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has roughly 3,900 lawyers in 58 offices in 33 countries.

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