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# SPACs Gain in Popularity

*by Trevor Pinkerton, in Houston*

Some renewable energy companies are thinking about special-purpose acquisition companies — called SPACs — as a possible means to access the public equity markets.

Through September, at least 16 investment groups have formed SPACs listed on the New York Stock Exchange or NASDAQ that are aimed at the energy transition, primarily in the clean tech and electric vehicle industries. Of these SPACs, at least four that have filed since August are specifically aimed at the renewable energy industry.

There have been more than 130 initial public offerings of SPACs this year that have together raised more than $50 billion in gross proceeds.

A SPAC is a company formed to raise capital with the aim of merging eventually with another company, thereby converting the target company into one that is publicly traded. The sponsor group forming the SPAC usually includes a management team with public company experience in a particular industry. Investors in the SPAC know the industry in which the SPAC plans to invest, but not the particular company. After raising capital this way, the sponsor begins the hunt for acquisition targets in that industry.

US Securities and Exchange Commission Chairman Jay Clayton said in September that the SEC and other regulators are taking a closer look at SPAC transactions and the quality of SPAC disclosures, including disclosures about the interests that the sponsor group will have in the combined company at closing and the group's incentives and motivations.

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**CHINA** is threatening to put some western companies on an "unreliable entities" list.

The government made the threat on September 19. Companies that land on the list risk being denied access to the Chinese market or barred from making investments in China. They could also have to pay fines or find their executives denied entry into China.

The action puts companies on notice that China may penalize them for bowing to pressure from western governments to take a harder line against China.

Sun Hong, a partner in the Norton Rose Fulbright Shanghai office, said the list will be maintained by a new "office of working / continued page 3

## SPACs

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### Typical Timetable

Most SPAC transactions follow a similar timetable.

The SPAC goes through an initial public offering process where a prospectus is prepared, an underwritten offering is conducted, and then shares in the SPAC are sold on a stock exchange. Because the SPAC has nominal assets, the process is much more streamlined than for an operating business.

The SPAC commits to a deadline during the initial public offering by which it must find a company to acquire, ideally in the target industry. It must not have already identified the company it plans to acquire (or else substantive disclosures would be required about the potential transaction, including target company financials).

The prospectus will explain what happens if the SPAC needs more time to conclude a transaction. The SPAC will probably have to redeem any shareholders who want out when the extension is granted.

The actual acquisition is called a "de-SPAC" transaction and is usually effected through a merger of the SPAC or its subsidiary with the operating company. The operating company shareholders exchange their shares for shares in the SPAC. The funds raised through the IPO remain in the combined company or are distributed to the existing shareholders of the target company as part of the consideration for their shares. Additional cash may be raised by bringing in PIPE investors.

PIPE offerings are a relatively fast way for public companies to raise capital in a private placement without the cost and delay of an underwritten public offering. "PIPE" stands for "private investment in public equity." (For more information, see "PIPEs clogged" in the January 2007 ***NewsWire***.)

The SEC must approve a registration statement for the stock consideration issued to the operating company shareholders, and issuance of additional SPAC shares to effect the merger must be approved by the SPAC's shareholders at a special shareholder meeting via a publically filed proxy statement.

Certain SEC filings are required in connection with the closing.

### Important Nuances

There are several important nuances common to SPAC transactions.

At the time of the IPO, the SPAC issues units (combining one share and a fraction of a warrant to purchase a share of common stock), generally at a per-unit price of $10.

The warrants are usually exercisable for $11.50 shortly after the de-SPAC transaction or one year after the IPO, whichever is later.

The funds received in the IPO are placed in a trust account, managed by a trustee and subject to a trust agreement. These funds are used to pay SPAC expenses and to fund the acquisition of an operating business.

The sponsor group also receives equity in the SPAC and usually holds a significant minority stake in the company after the de-SPAC transaction. The sponsor group holds common equity with special rights called "founder shares" that, after the de-SPAC transaction, usually leave the sponsors holding 20% of the company on a fully diluted basis. This is called the sponsor's "promote." The sponsors also receive founder warrants that typically have a cashless exercise feature and are not redeemable, but otherwise have terms similar to any warrants issued to the IPO investors. Warrants are options to buy (or take, in the case of cashless exercise) more shares.

The SPAC shareholders must approve the de-SPAC transaction at a special shareholder meeting. They have the option at that time to cause the SPAC to redeem their shares in the SPAC for a specified value (the original share price), which is paid with funds from the trust account.

The redemptions that occur in connection with the de-SPAC transaction can tap into

A SPAC raises money through a public offering to invest in an as-yet unidentified company in a target industry.

anywhere from 0% to 100% of the funds in the trust account. Average redemptions historically have laid claimed to around 50%.

These redemptions can significantly deplete the trust account that was meant to provide cash at closing to the combined entity and possibly also to the operating company shareholders. This often necessitates an investment by a PIPE investor, as well as potential backstop obligations from the sponsor group or other third-party investors. Examples of backstop efforts are an additional equity investment by the sponsor group or others to cover any shortfall in cash needed to make the full payments promised to the existing shareholders of the target company, transferring founder shares or warrants to the target company owners or to PIPE investors, having the sponsor group or other investors pay transaction costs or commit to buy SPAC shares in the open market.

The redemption offer does not apply to the public warrants issued to the SPAC investors in the IPO. These warrants remain outstanding even if SPAC shareholders cause the SPAC to redeem their shares instead of staying in through the de-SPAC transaction.

The sponsor group and other directors and officers typically waive any right to have their founder shares redeemed by the SPAC.

The ability of the SPAC shareholders to cause the SPAC to redeem their shares gives them essentially two decision points. They make an initial decision to invest based on the management team put together by the SPAC and then to confirm the decision when that team identifies the operating company to be acquired.

The de-SPAC transaction must be completed within a specified time after the IPO (often 18 to 24 months). However, some SPACs have automatic extension provisions if the SPAC has entered into a letter of intent or acquisition agreement with a qualified target, even if the transaction is not yet closed. However, if the deadline is reached, the SPAC will be forced to seek an extension by shareholder vote and will also risk losing SPAC shareholders who choose to redeem their shares through a tender offer process in connection with each extension. Each round of extensions and redemptions effectively reduces the cash available at closing.

## Attractions

SPACs have become a popular method of going public. While the structure has been around for decades, the number of SPAC IPOs has increased in each of the last four years. More than $50 billion has been raised in SPAC IPOs in 2020 through early October, including a large amount during August, a traditionally slow period for the capital markets.

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mechanism" in the Ministry of Commerce.

The government said it will label companies as unreliable entities if they "endanger the sovereignty, safety and development interests of China" or "discontinue normal transactions with Chinese enterprises, other organizations or individuals in breach of normal market trading principles" or "discriminate against such persons and severely damage their legitimate interests."

The ministry will notify any companies it intends to add to the list. The companies will then have a period of time to fix their behavior before penalties are imposed.

**THE TRUMP BULK-POWER SYSTEM ORDER** said guidance would be issued by the US Department of Energy by September 28, but November may be more realistic.

It took the US Department of Commerce until November last year to issue guidance to implement a similar Trump executive order about the US telecom network.

Meanwhile, the Federal Energy Regulatory Commission issued a "notice of inquiry" in September to collect information about what potentially risky equipment is being used by US power companies and what steps they are taking to mitigate the potential for such equipment to harm the grid.

The FERC notice asks five questions. The first question is to what extent equipment or services are being supplied by "covered companies," meaning Huawei, ZTE or any entity that is "owned or controlled by, or otherwise connected to" the Chinese government.

Two years ago, FERC ordered 288 US utilities and other entities that are subject to North American Electric Reliability Corporation standards to adopt plans that include "security controls for supply-chain management for industrial control system hardware, software, and services associated with bulk electric system operations." The directive is in FERC Order No. 850.

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While the SPAC structure obviously has benefits for the sponsors (the 20% fully-diluted ownership of a successful operating business for minimal investment of capital), it has also become popular with both the investing public and private operating companies looking to go public.

This popularity is due to several factors.

Operating company CFOs like it because it avoids the protracted process and uncertainty around a traditional IPO, especially during the COVID-19 pandemic.

It takes less time to turn a private company into a publicly traded company. The de-SPAC transaction often takes only six months from the initial letter of intent between the target and the SPAC through closing of the de-SPAC transaction. Taking a company public through an IPO normally takes a full year.

Another attraction is the combination for the operating company of a cash payout to its private shareholders at closing (through a portion of the trust account funds and PIPE) and access to the liquidity of the capital markets after closing through the public equity issued in the acquisition.

SPAC investors like it because of the unique optionality built into the structure. They have extra upside through warrants and can walk away from an undesired acquisition by forcing a redemption. An investor is basically buying a "look-and-see" opportunity with an experienced management team actively searching for viable M&A candidates.

### Common Issues for SPAC Targets

At the same time, de-SPAC targets and their management need to approach SPAC transactions with their eyes wide open to some of the risks and uncertainties associated with SPACs.

When assessing the pro forma ownership of the combined company and the pricing of the de-SPAC transaction, the target should consider the likely event that some significant portion (or all) of the trust account that the sponsor group is bringing to the table could walk out the door through redemptions of SPAC shares.

Consider that in light of those redemptions, there may be significant renegotiation of the deal terms after execution of the acquisition agreement, which may require "backstop" agreements with the sponsor and other parties, including the PIPE investors, to put in more money, sell additional equity or reallocate founder shares, and these efforts can suck up management time of the target company before closing.

The SPAC sponsor group will probably own 20% of the combined entity on a fully diluted basis (through their founder shares), have warrants that are exercisable after closing if the stock price rises to $11.50 and negotiate for significant board representation, and it may hold certain approval rights and downside protection, and yet the sponsors may not show up with any cash left in the trust account. This risk is often mitigated to a degree by forcing the sponsor group to forfeit founder shares to cover redemptions by SPAC IPO investors, which helps pro forma ownership but does not address the depleted cash.

Due to redemptions, it is not unusual for a large portion of the deal consideration to end up coming from PIPE investors, and they may request board representation and require broad registration rights.

The target operating company may not have effective recourse against the SPAC to enforce pre-closing rights in the acquisition agreement (including the obligation to close) because of required protections surrounding the trust account and its cash.

Among the issues the target company will have to negotiate with the SPAC include what role the target's management will play in the combined company and how many board seats of the combined entity will be held by board members of the target. Major shareholders of the target will want to retain their existing board representation. The existing target board members may or may not be considered independent directors after the de-SPAC transaction under the relevant exchange or SEC regulations. Exchange rules and SEC regulations require at least a majority of board seats in publicly traded companies be held by independent directors.

The target will need to have financial statements that comply with PCAOB (Public Company Accounting Oversight Board) standards and will need to work with its auditor (or find an appropriate auditor) to produce these financial statements, which can be an item with significant lead time.

The parties need to have a plan for practical liquidity in the equity markets after the transaction because the lack of underwriting by investment banks (a key element of the traditional IPO) means that the combined company will have less analyst coverage and trading volume than a company going public through a traditional IPO.

The SEC still views some SPACs with a wary eye, due to their history as a means around the traditional IPO process and a way to invest in speculative target companies that have not undergone the traditional vetting involved in an IPO. ◎

# LIBOR End May Disrupt Emerging Market Lending

*by Jeremy Hushon and Kanwal Majeed, in Washington*

The anticipated cessation of LIBOR at the end of 2021 presents an ominous predicament for foreign lending into emerging market economies.

Borrowers in these markets must often account for revenues earned in local currencies and deal with central bank requirements regarding foreign exchange and currency transfers and other regulatory controls.

In many cases, such processes have hardened around the predictability afforded by forward-looking term LIBOR based rates. LIBOR's replacement, at least for some period of time, by a non-forward looking benchmark may make it far more challenging for borrowers to comply with their loan payment obligations and could increase payment default risk.

LIBOR's end is also likely to disrupt new foreign loans into emerging markets until new measures and practices are adopted by the relevant market participants.

## Replacement of LIBOR

For several decades, LIBOR has been the most widely used benchmark interest rate in the global financial markets.

It is intended to reflect the cost of lending across a wide range of financial products, including mortgages, corporate debt, floating rate notes and interest rate swaps.

LIBOR is determined by averaging the rates that are submitted by a panel of banks to the Intercontinental Exchange Benchmark Administration. More than $200 trillion worth of financial contracts use US dollar LIBOR as their benchmark rate.

However, the pool of transactions that drive the methodology for LIBOR has been steadily shrinking since the 2008 financial crisis, causing regulators to lose confidence that LIBOR continues to be an accurate reflection of funding cost. The Financial Stability Board, an international body established by the G20, has been working with central banks, regulatory authorities and other market participants since 2014 to find new alternative reference rates to implement an orderly transition away from LIBOR. */ continued page 6*

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Responses to the questions in the latest notice of inquiry are due by November 22, 2020.

President Trump issued an executive order on May 1 imposing an immediate ban on the purchase, use or transfer of as-yet unidentified foreign adversary equipment that might be used to harm the US power grid. It is Executive Order 13920.

Many project developers are requiring equipment vendors and construction contractors to represent that no equipment will be used that runs afoul of the Trump executive order. Vendors are being asked to commit to use of commercially reasonable efforts to get their equipment on any pre-approved lists that the US Department of Energy decides to publish. Developers retain the right to terminate contracts that violate the Trump executive order.

Some companies selling projects are concerned about their ability to represent that projects are in full compliance with US law given the uncertainty around the Trump executive order.

There has been a move away from use of Chinese equipment and contractors for some types of equipment. (For more detail about market reaction, see "Trump bans certain power equipment" in the June 2020 *NewsWire*.)

The Department of Energy named the foreign adversary countries that are the focus of the Trump executive order in July. They are China, Russia, North Korea, Iran, Libya and Venezuela. Only China is a significant supplier to the US power industry. (For more detail, see "DOE starts implementing Trump bulk-power system order" in the August 2020 *NewsWire*.)

Meanwhile, the US House of Representatives passed three bills at the end of September dealing with cybersecurity and the electricity grid. One of the bills would create a new assistant Energy secretary position focused on emergency and security functions related to energy supply. Another would require the department to set up a voluntary "cyber-sense" program to test the safety */ continued page 7*

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After 2021, panel banks will no longer be compelled by the Bank of England and the UK Financial Conduct Authority to submit the rate information that is used to calculate LIBOR. The panel banks consist of between 11 to 16 banks for each of the underlying currencies (dollars, sterling, euros, Swiss francs and yen), and each bank submits data on every available LIBOR tenor for the applicable currency.

LIBOR may end before year end 2021 if the Bank of England determines that LIBOR does not reflect the true cost of funds.

All contracts using LIBOR will need to be amended before the deadline or risk having an interest rate that can no longer be determined.

Financial institutions are already undertaking the transition to replacement benchmarks such as risk-free rates. However, such efforts have not seriously commenced in most emerging market countries, where few central banking authorities have focused on the transition away from LIBOR to a new benchmark rate.

### Rising Consensus Around SOFR

In the United States, the transition from LIBOR has been overseen by the Alternative Reference Rates Committee of the Federal Reserve Board.

The "secured overnight financing rate" — called "SOFR" — has been selected as the preferred fallback rate for dollar-denominated instruments by the Federal Reserve Board because it meets international standards for benchmark quality in light of the depth and liquidity of the markets in which it is produced and administered.

SOFR is an overnight, secured, nearly risk-free rate that is calculated historically and published daily.

SOFR reflects the cost of borrowing cash overnight, which is collateralized by US Treasuries. The Federal Reserve Bank of New York collects transaction data composed of repurchase agreements. A repurchase agreement is a type of short-term secured loan where securities are sold to a buyer and the seller agrees to repurchase those securities at a later date for a higher price. The difference in the original sale price and the repurchase price reflects interest paid on the loan and is called the repo rate. There are three types of repo rates cleared though the Fixed Income Clearing Corporation that are used to determine SOFR. SOFR is then published by the Federal Reserve Bank of New York each day and reflects the prior day's data.

In contrast, LIBOR is an unsecured forward-looking rate published at various maturities that can range from overnight to one week, one month, two months, three months, six months or one year.

There are currently nearly $800 billion worth of transactions on a daily basis underlying the determination of SOFR, far greater than the value of the transactions used to determine LIBOR. The median daily volume of three-month LIBOR transactions (the most commonly used tenor for LIBOR) is less than $1 billion, and it can sometimes drop below $500 million.

As SOFR is an overnight rate based on US Treasuries, unlike term LIBOR, it does not seek to align to a lender's cost of funds over the relevant interest rate period. Furthermore, neither SOFR nor LIBOR accounts for economic, country and counterparty risk typically addressed through the addition of a margin to the relevant benchmark rate.

Thus, the switch to SOFR will require the addition of two separate margin components, one to account for lenders' costs of funds over each interest period to which it is being applied and the second to address the traditional credit risks lenders or markets perceive relating to a borrower or its operating environment.

Ultimately, the determination and agreement upon the interest rate to be applied to transactions is likely to become more complicated with new components to be considered by lenders and borrowers.

### SOFR Variations

Several variations of SOFR have been considered as possible benchmark replacement options.

Concept credit agreements have been published by the Loan Syndications and Trading Association in the United States to demonstrate the use of SOFR-based rates in practice.

"Daily simple SOFR" is determined by multiplying the daily published rate to the outstanding principal of the loan to reflect the amount of interest accrued on each day of the interest period. Such interest amounts are aggregated over the interest period with the amount of interest payable in arrears at the end being equal to the sum of such amounts.

By contrast, "daily compounded SOFR" is calculated by compounding interest daily during the interest period by adding each day's interest to the principal balance of the calculation for the following day. The accumulated additional principal and interest is payable in arrears at the end of the interest period.

Daily compounded SOFR "in advance", or "term SOFR," is predicted to be a forward-looking rate for SOFR. It would be known at the beginning of each interest period and would more closely mirror market conventions for LIBOR.

The implementation of term SOFR will require a volume of trading and liquidity in SOFR-based term-loan products that will permit market participants to advise on rates based on market transactions. There are many competing views about when and how this may be accomplished. Furthermore, the predictive qualities of any forward-looking term rate may face the same challenges that have caused LIBOR's impending demise. However, much of the hesitancy surrounding the adoption of daily SOFR as LIBOR's replacement may be attributed to continued desire in the marketplace for forward-looking interest-rate measures.

Several other global financial centers have introduced their own alternative reference rates, such as the "sterling overnight index average" in the UK administered by the Bank of England, the "euro short-term rate" administered by the European Central Bank and the "Singapore overnight rate average" administered by the Monetary Authority of Singapore.

While SOFR is expected to be the primary replacement for US dollar LIBOR as the global benchmark, the end of LIBOR is likely to lead to adoption of a broader range of international rates focused on other major currencies and regional banking practices.

For borrowers in emerging markets, this may provide additional options, but also may vastly complicate the process of selecting the most beneficial financing structure.

## Implications of SOFR Adoption

With a forward-looking interest rate such as LIBOR, both the bank and the borrower have certainty with respect to the amount and timing of future interest payments because the interest rate is determined and fixed at the beginning of each interest period.

Borrowers know the exact amount of interest they will need to pay on the next interest payment date and may plan accordingly. In addition, borrowers may enter into long-term interest rate swaps to manage exposure to interest-rate fluctuations over the entire term of the loan. Most lenders will similarly enter into hedging transactions to manage and match any interest rate fluctuation risk in respect of their own liabilities over the interest period. In this regard, with LIBOR, both borrowers and lenders have been able to manage credit risk associated with interest rates.

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of bulk-power system equipment from cybersecurity threats, maintain a database and offer technical assistance to utilities. The bills still need to clear the Senate.

**MORE THAN 3,400 COMPANIES** have filed suit against the Trump administration to get back tariffs paid on Chinese products.

The tariffs are being collected under section 301 of the Trade Act of 1974, which authorizes the government to impose tariffs on countries that violate US trade agreements or engage in "unreasonable" or "discriminatory" trade practices. All of the cases have been filed in the US Court of International Trade.

HMTX Industries filed the first suit on September 10, 2020. The others are "me-too" suits that hope to piggyback on whatever relief HMTX Industries receives.

The Trump administration has invoked section 301 to impose five major sets of tariffs. Four were tariffs against different lists of Chinese products. Approximately two thirds of US imports from China are subject to section 301 tariffs ranging from 7.5% to 25%.

Section 301 sets a 12-month time limit for the government to impose tariffs after concluding an investigation. HMTX Industries charges that the list 3 and list 4 Chinese tariffs were imposed after the deadline. Companies have at least two years to sue for refunds. That deadline has now arguably expired for list 3 tariffs, but suits may be filed until at least August 20, 2021 for refunds of list 4 tariffs.

A ruling is expected soon in a separate case challenging section 301 tariffs that the Trump administration imposed on imported steel.

Meanwhile, the United States Trade Representative launched a new section 301 investigation on October 5 into whether Vietnam is manipulating its currency to the detriment of US companies. Exchange rates have historically been the domain of the US Treasury.

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A switch to a backward-looking rate like SOFR will no longer permit borrowers to know the amount of interest they will owe at the start of an interest period.

If financial markets reach an environment where SOFR sees a fair amount of fluctuation, borrowers may have to create reserves to ensure that they will have the necessary funds on hand to make interest payments. (See "SOFR too volatile?" in the August *NewsWire*.)

Ending LIBOR will disrupt new cross-border lending into emerging markets.

The backward-looking nature of SOFR also creates a possible administrative challenge. With LIBOR, lenders are able to invoice borrowers for their upcoming interest payments at any time during the interest period. With SOFR, such advance invoicing or notice will not be possible, as the final rate will not be determined until the interest payment date.

The US commercial bank market seems to be coalescing around a short look-back period to calculate daily simple SOFR or daily compounded SOFR. In such a look-back period, the interest rate applied to a particular payment period may be shifted a few days earlier so that the final interest amount will be determinable a few days before payment is due.

### Impact on Emerging Markets

In emerging market economies, the loss of certainty about the interest-payment amount due at the end of each interest period may create significant issues for borrowers.

First, since the revenues of many such borrowers are earned in local currency, borrowers often need to account for foreign-exchange as well as interest-rate fluctuations when considering their hard currency needs at the end of each the interest period.

Second, to the extent that central banks or other relevant monetary authorities require advance notice or proof of a borrower's foreign-currency needs, the inability to produce an invoice or even a firm calculation until the interest payment date when such funds are due is obviously a problem.

By way of example, in Senegal, foreign currency loans must be authorized by the Ministry of Economy and Finance. Even once authorized, to obtain the foreign currency to make payments on such loans, permission must still be sought from the regional central bank for West Africa. Such permission is typically sought days if not weeks in advance of when the currency is required.

With forward-looking term LIBOR, where the interest payment amount is known far in advance, borrowers and their local banks have generally been able to handle this hurdle without difficulty.

If the international US dollar lending market shifts to SOFR or other backward looking interest rates, borrowers will not know their currency needs until the payment date (or if a short five-day look-back is expected, then a few days in advance). For a country like Senegal, the volume of euro-based foreign lending and the continued viability of EURIBOR, at least in the short term, may lessen the impact. However, if sufficient planning and transition procedures are not implemented by all parties before LIBOR disappears, then serious disruption in both payments and new loan activity for US dollar transactions is likely to occur in countries with foreign-exchange controls.

One possible solution to the loss of interest-rate certainty and the additional time parties in emerging markets require to make foreign currency payments would be to permit a longer look-back or shift in interest determination. However, a greater mismatch between the actual interest period and the period used for determining the interest rate will make it more difficult for banks to manage their own exposure. It will further misalign the bank's own cost of funds with the amount of interest it will receive.

A longer look-back or shift in the observational period of the interest rate will also create a significant divergence in practice between lending practices in developed markets and those in emerging markets.

If the practice in certain emerging markets requires more significant interest rate shifts, then it may stifle banks' ability and willingness to provide new loans to borrowers in such jurisdictions.

A switch from LIBOR to SOFR might also run afoul of certain laws and regulations in emerging market countries.

For example, the market shift from what has been a stable and long-standing practice of forward-looking LIBOR to SOFR might inadvertently cause foreign lenders to contravene Kenya's consumer protections laws. Michael Kontos, the managing partner of Walker Kontos, a Kenyan law firm, has noted that the switch to an interest rate that is not prospective in nature, and therefore transparent to a borrower, might create technical grounds for a borrower to bring a challenge under Kenyan law.

The transition also may create additional regulatory compliance issues. For example, all foreign loans to Brazilian entities must be registered as foreign capital under the financial operation registration (ROF) module of the Central Bank of Brazil, presumably to aid the country in managing its foreign currency needs and exposures. Jose Cobena, counsel in the Norton Rose Fulbright São Paolo office, notes that amendments to switch existing term loans from LIBOR to SOFR will require a new or updated ROF and may also face revised tax treatment.

The fracturing of LIBOR as the global benchmark into new reference rates across varying jurisdictions may present challenges for banks in multiple regions to co-finance projects in emerging markets.

It may splinter or complicate the agency roles for banks that seek a centralized actor to manage the flow of information and payments between borrowers and lenders. With the source of LIBOR and market conventions for interest-rate determination being well established, it is often possible for a single agent bank to handle this responsibility for a group of lenders. The switch to SOFR, or perhaps multiple benchmark rates within a syndicate of loans, as well as additional uncertainties surrounding adjustments to be made to new short-term benchmarks to better reflect longer interest periods, may make agency roles far more challenging, at least until such time as standard procedures and methodologies are widely adopted.

## Impact on Local Lenders

The end of LIBOR will also have a significant impact on banks in emerging markets, many of whom have long-term credit arrangements with international banks based on US dollar loans.

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The Department of Commerce announced earlier this year that it will treat currency undervaluation as a factor when deciding whether to impose countervailing duties on imports. Commerce is investigating the extent to which weakness in the dong is giving Vietnam an unfair advantage in selling tires into the US market.

The Trump administration suspects Chinese manufacturers of shifting exports through Vietnam in reaction to US tariffs on Chinese imports. The trade deficit with Vietnam is expected to hit $70 billion this year compared to $39 billion in 2018 and $56 billion in 2019.

In a separate action, Commerce adjusted the anti-dumping and countervailing duties on Chinese solar panels in a *Federal Register* notice on October 2.

Panels made by Chinese panel manufacturer Risen are subject to duties of 106.39%. Trina panels are subject to duties of 50.33%. Another 16 Chinese solar panel manufacturers, including Canadian Solar, JA Solar, Jinko and Yingli, are subject to duties of 68.93%.

Other Chinese panel manufacturers not on the list of 16 face duties of 238.95% on their solar panels.

Importers must post cash deposits when the panels pass US Customs.

These latest figures are the final duties for panels imported in 2017 and 2018.

The Commerce Department recalibrates the actual duties over time and adjustments are made to the cash deposits In such cases, importers may be required to pay more or receive refunds.

*The Federal Register* notice reminded importers that they must file certificates confirming that they have not been reimbursed for the duties by the Chinese manufacturers. Otherwise, Commerce will assume the duties were reimbursed, in which case it will collect the reimbursement as an additional duty.

Some solar panels are being delivered to the US on a DDP (Incoterms) */ continued page 11*

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Such banks will need to re-evaluate their interest-rate exposures to foreign lenders, including considering whether their own loan portfolios and hedging transactions should be altered to better control their exposure to the impending switch to SOFR.

Local banks will also be beholden to the speed at which central banks and other monetary authorities adjust to the end of LIBOR.

In El Salvador, banks and financial institutions are required to report their liquidity status, which includes information on the entity's ability to honor its debts as they fall due, to the Superintendency of the Financial System each month. The central bank of El Salvador has not yet adopted any rules or announced a transition plan away from LIBOR. Zygmunt Brett, partner at the law firm BLP Abogados, notes that the private sector has undertaken initiatives to assess LIBOR exposures, but without a coordinated transition plan from the central bank, the end of LIBOR may present liquidity, operational and regulatory risks for both banks and borrowers.

Lending practices could diverge in developed markets compared to emerging markets.

Undoubtedly, some countries and banks will be better prepared than others. Those that choose to delay measures for too long may face increased financial risk and interruptions to their borrowing and lending operations as counterparties seek assurances that the transformed interest-rate risk has been mitigated.

There is significant variation in practices for interest-rate setting by banks in emerging markets.

While some markets and banks are relatively transparent and rely on LIBOR or other widely accepted benchmark rates, others use less straightforward rates typically presented as designed to reflect their cost of lending. In either case, banks in emerging markets will probably need to implement new rate structures as both the benchmark rates and their costs of funds are likely to change.

The lack of market transactions and transparency that precipitated the end of LIBOR might also trickle down to banks in emerging markets, leading to more transparent local benchmarks. As an example, in September 2019, the Reserve Bank of India required the country's banks to transition to an external benchmark for interest rates.

### Into the Void

While the end of LIBOR has been foretold for many years, the lack of an accepted forward-looking alternative together with the lingering hope that one might arise, has caused many banks and other financial institutions to delay their plans for necessary transitions.

Both lenders and borrowers may have to accept backwards looking interest rates for perhaps months or years, as there may be no forward-looking rate with the type of widespread acceptance as LIBOR for some time.

As year end 2021 approaches, borrowers and banks that fail to undertake an assessment of their exposures to LIBOR and transition to new practices and procedures are risking defaults with existing loans and interruptions in new loan activity. ◎

# FERC Opens One Door and Closes Two Others

*by Bob Shapiro and Caileen Kateri Gamache, in Washington*

Three orders by the Federal Energy Regulatory Commission in September will have significant effects on different segments of the US independent power market.

One order will make it harder for solar and other renewable energy projects that supply up to 80 megawatts to the grid — and add a battery — to qualify for power purchase agreements with utilities in parts of the United States that are not part of organized markets.

Another order will make it more difficult for renewable energy projects in [and around] New York to qualify for capacity payments from the New York grid operator.

The last order requires regional grid operators to let owners of rooftop solar and other "distributed energy resources" who can aggregate them earn additional revenue by supplying electricity or other services to the grid.

## Broadview Solar

Since 1981, FERC has consistently held that the size of a qualifying small power production facility or "QF" is measured by the amount of capacity it can "send out" to the grid.

A project cannot exceed 80 megawatts to retain small-power QF status.

All electric utilities are required by a 1978 federal law called the Public Utility Regulatory Policies Act, or "PURPA," to buy electricity from QF projects for the "avoided cost" that the utility would pay to generate the electricity itself. Since 2005, utilities have only had an obligation to purchase from QFs smaller than 20 megawatts, except in parts of the country without organized power markets where QFs can be as large as 80 megawatts. In a recent order, FERC reduced a utility purchase obligation in areas served by organized power markets to projects that are five megawatts or smaller in size.

FERC overturned settled principles in early September in an order revoking QF status for a solar project in Montana called Broadview Solar. The proposed project has a net capacity of 80 megawatts, even though the gross capacity of the solar modules will be 160 megawatts. It will also include a 50-megawatt battery or "BESS."

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basis, meaning delivered with the transportation costs, VAT and duties paid by the panel manufacturer. Such arrangements could lead to double duties.

Stefan Reisinger, a trade lawyer in the Norton Rose Fulbright Washington office, said that while technically accurate, developers buying Chinese solar panels duty paid should be able to avoid double duties by reducing the declared value of the panels upon entering the United States by the amount of the DDP price attributable to the duties.

Separately, Commerce said in September that it is considering placing duties as high as 135.06% on steel wire from Turkey used in construction projects to strengthen concrete panels to offset subsidies by the Turkish government.

At the same time, the US Court of International Trade declined to delay enforcement of a July order for the Trump administration to refund the extra section 232 tariffs that the president imposed on Turkish steel. The US doubled a tariff on Turkish steel from 25% to 50% on national security grounds amid a diplomatic spat in 2018.

The price of aluminum may be headed up in the US. The Commerce Department announced on October 9 that it will impose anti-dumping duties on aluminum imported from 18 countries. Importers will have to post cash deposits of 80% for India, 137% for Brazil and 353% for Germany. The required deposits are 30% or less for imports from 13 other countries. The final dumping margins will be calculated early next year.

The US has been collecting a 10% tariff on imported aluminum since March 2018. The anti-dumping duties will be collected on top of the existing tariff.

Finally, two US wind tower manufacturers – Arcosa Wind Tower and Broadwind Towers – asked the US government on September 30 to slap anti-dumping and / continued page 13

## FERC

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The Broadview order contributes to a recent trend in unpredictable energy regulatory orders disturbing developer and investor expectations and elevating change-in-law risks.

Broadview Solar petitioned FERC for a declaratory order that the project will qualify as a QF.

Broadview acknowledged the 80-megawatt capacity limit in the law, but explained that the project inverters, which convert direct current (dc) power from the project to alternating current (ac) power as necessary to send power to the grid, are not capable of converting any more than 82.5 megawatts.

With parasitic load and losses of 2.5 megawatts ac from the inverter to the point of interconnection, the total amount of power that the facility can send to the grid is limited to 80 megawatts. The only way to increase the project's capacity would be to install additional inverters. The project's interconnection agreement also expressly limits the facility output to 80 megawatts. Broadview explained that it designed the project with an oversized solar unit combined with a BESS to increase the capacity factor and significantly enhance efficiency. The 50-megawatt BESS energy also must be transformed into ac power through the same inverters, so the BESS output and output from the solar arrays together cannot exceed 80 megawatts ac at the point of interconnection.

A September FERC order will make it harder to sign utility PPAs and complicate adding batteries.

Under established FERC precedent, Broadview's design would have been sufficient to qualify the project as a QF because it is physically impossible to send more than 80 megawatts to the grid.

FERC held nearly 40 years ago in an order called Occidental that determining "a facility's power production capacity is not necessarily determined by the nominal rating of even a key component of the facility." Instead, "the electric power production capacity of the facility is the capacity that the electric power production equipment delivers to the point of interconnection with the purchasing utility's transmission system."

In Broadview, FERC said that, "on further consideration" (after 40 years of following Occidental) the "send-out" analysis in Occidental is inconsistent with PURPA.

It held that the "power production capacity" of a facility is the maximum gross power production capacity, less certain parasitic loads and losses. According to FERC, the parasitic loads and losses cannot take into account controls, inverters and other "output-limiting devices" that restrict the amount of power that can interconnect.

As the dissent noted, FERC simply took one component of a power plant (the DC value of the solar modules) and called it the entire facility. It ignored the fact that the output from that component cannot synchronize with the grid without passing through an inverter to convert it to ac power, and the inverter size limits the output as measured at the grid to 80 megawatts. Therefore, the "facility is physically incapable of producing more than 80 MW of electricity for any subsequent use."

FERC said all existing QFs will be grandfathered under the prior regime. The facility must actually be a QF — meaning it must have already submitted a FERC Form 556 — to qualify for grandfathering. Simply establishing a legally enforceable obligation or PPA with a utility pursuant to PURPA is insufficient.

The Broadview order turns on the fact that the solar system part of the facility alone (absent the inverter) exceeds 80 megawatts, and expressly dodged addressing the impact of the BESS on the determination.

The interconnecting utility, which opposed the QF determination that Broadview wanted, argued that the capacity of the BESS should be additive, because FERC "currently treats storage facilities as primary generation resources and does not treat them as ancillary or secondary to the generation process." In contrast, the dissent said the BESS "cannot 'produce' power in any conventional sense of that term," since its output must pass through the inverters to deliver output to the grid.

Entities seeking to combine renewable resources with a battery or other storage device are left without clarity as to the impact of storage on the facility's QF eligibility.

At a minimum, if a renewable energy project must be a QF (in order to obtain power purchase agreements with vertically integrated utilities outside of liquid wholesale markets), the developer should consider requesting clarification from FERC before committing to include a BESS with a renewable resource when the combined capacity will exceed 80 megawatts.

Applying this new policy to an associated BESS system would seem contrary to the policy rationale behind the recent FERC Order No. 845, which seemed to encourage combining batteries with variable renewable energy resources in order to take advantage of unused interconnection capacity. (For more information on Order No. 845, see "Big changes in how new power projects connect to the grid" in the June 2018 *NewsWire*.)

## New York Capacity Auctions

FERC issued a separate order in September rejecting a proposed modification to the capacity bidding rules used by the New York independent system operator, or NYISO, that would have allowed certain facilities that meet the state's clean energy priorities to avoid offering a minimum price when bidding into the state's capacity auctions.

The priority would have permitted the capacity from these renewable projects to clear the capacity auctions.

Under current NYISO rules, a new project would have to clear in 12 consecutive monthly auctions in New York City and surrounding metropolitan areas before it could avoid having to offer a minimum price in future auctions under a so-called "buyer-side market power mitigation rule."

This is analogous to the PJM minimum-offer price rule, or MOPR, construct. Using essentially the same rationale that it used to modify the PJM capacity auction rules to require all new renewable generation with a state subsidy to offer a minimum-offer price in PJM capacity auctions, FERC held that giving a preference to any technology is discriminatory, and it rejected the NYISO proposal to exempt from offering a minimum price projects that the state wants to encourage.

The existing rules, which were not changed, already provided certain exemptions from the mitigation / continued page 14

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countervailing duties on towers from India, Malaysia and Spain.

The United States Trade Representative and Commerce Department issued anti-dumping and countervailing duty orders in late August against wind towers from Canada, Indonesia, Korea and Vietnam in response to a petition by the same two tower manufacturers.

Towers imported from China have been subject to a 25% duty under section 301 of the 1974 Trade Act since August 2018.

The two US manufacturers charge that towers from India, Malaysia and Spain increased to $190.8 million during the first six months of 2020 compared to $86.5 million in all of 2019 and $29.3 million in 2018.

**NO NEW OFFSHORE WIND LEASES** will be issued by the US government for the area off North Carolina, South Carolina, Georgia and Florida for a 10-year period starting July 1, 2022.

The moratorium does not affect offshore wind development in areas that have already been leased.

President Trump imposed it in a memorandum to the US Interior secretary on September 25. The moratorium bars any new federal leases for "exploration, development or production" — including production of oil and gas and electricity generation — in federal waters off the four states. The US claims jurisdiction out 200 miles to sea. The moratorium would apparently also apply to leases for use of underwater turbines.

Trump said at a campaign rally at the Newport News airport later on September 25 that he plans to extend the moratorium to the area off Virginia.

**TAX EQUITY INVESTORS** who invested in North Carolina solar projects expecting to claim a 35% state tax credit are watching two cases closely.

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## FERC

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rule, including for projects that satisfy one of two types of price-forecast tests. Test A requires a demonstration that the first-year capacity cost of the project will exceed the minimum-offer price. Test B requires a showing that the average forecasted price for the first three years is higher than the minimum price.

NYISO wanted to modify these tests by giving priority to renewable resources up to a capacity cap.

The renewable resources to which it wanted to give priority would be picked ahead of conventional fossil resources that may have a lower cost.

NYISO explained in its application that since the state has aggressive clean energy requirements, relying solely on economic merit order would incentivize conventional energy when those projects will not be needed to meet the state's clean energy goals. NYISO also explained that its proposal would not have the effect of suppressing market prices, because the total amount of capacity to be exempted from the minimum-price rule would not be affected.

In rejecting the proposal, FERC ignored the argument that the NYISO modification would not suppress market prices, and ruled strictly on a claim that the priority was discriminatory. It also ignored the facts that the proposal had the support of the NYISO independent market monitor as well as the New York Public Service Commission and a large majority of NYISO stakeholders and had no significant adverse intervention.

The ruling does not eliminate the ability of renewable resources to obtain an exemption by meeting existing tests. However, it will make doing so significantly more difficult.

The effect on state ratepayers is expected to be a significant increase in costs, as they would have to pay the capacity costs of conventional resources that clear the auctions as well as the capacity value associated with the renewable resources required to meet the state's renewable energy standards.

FERC noted this potential, as it did when it imposed the new MOPR requirements in the recent PJM capacity auction order, but again relied on a federal court holding in a different context that states "are free to make their own decisions regarding how to satisfy their capacity needs, but they 'will appropriately bear the costs of [those] decision[s] . . . including possibly having to pay twice for capacity."

## Rooftop Solar

A FERC order in mid-September will let companies that develop small-scale projects, like rooftop solar, earn additional revenue by participating in regional wholesale power markets through aggregation of systems that the companies also own and use to sell electricity to residential and business customers.

The order, known as Order No. 2222, is designed to allow small distributed energy resources or DERs to aggregate systems in order become large enough to sell one or more energy services in competitive regional transmission organizations, or RTOs. RTOS include PJM, MISO, NYISO, CAISO, SPP and ISO-NE.

The new policy does not apply to ERCOT, which is regulated by the Public Utility Commission of Texas, not by FERC.

The order requires the RTOs to amend their tariffs to enhance commercial viability of a wide range of distributed resources by allowing DER aggregators to sell capacity, energy and ancillary services from these resources. "DER" is defined as "any resource located on the distribution system, any subsystem thereof or behind a customer's meter."

Thus, battery or other energy storage, rooftop solar, fuel cells, electric-car batteries and similar sources of energy could be eligible for such aggregation.

The minimum aggregation size for eligibility as a market participant in an RTO is 100 kilowatts.

FERC said that permitting such DER aggregation will increase market competition and could improve load forecasting and reduce over-procurement of resources.

For the DER resource owners, the order has the potential to add another revenue source, provided that the service offered in the RTO does not lead to double counting of the energy service provided.

The new policy also requires the RTOs to take into account the specific, sometimes multiple characteristics and functions that the DER resources can provide when redesigning their tariffs. For example, some battery storage can be a generation resource, a demand resource or a transmission resource and may be able to participate in different markets at different times.

Each RTO has nine months to file new tariffs to accommodate aggregation of DER resources.

Given the complexity of the task, most RTOs are likely to seek an extension of the compliance deadline. The policy is subject to rehearing. The rehearing deadline is October 19. If a rehearing is denied, the RTOs or other intervenors, including competitive suppliers, could still challenge the new policy in court. ◎

# COVID-19 and Business Interruption Claims

*by Aditya Rebbapragada, in Singapore*

Several project developers and other businesses around the world have filed claims under business interruption insurance policies due to interruptions in work during lock-downs resulting from COVID-19.

More than 1,000 COVID-19-related insurance lawsuits are estimated to have been filed in the US alone.

The British High Court decided a test case in September.

## UK Test Case

Business interruption insurance usually requires the insured party to show damage to *assets* from a cause not excluded under the policy.

In some cases insured parties may take the view that they have recourse under business interruption insurance where there is denial of access to a project or business site or interruption to operations as a consequence of an infectious disease contracted by any person while at the site or due to a lock-down, even though no damage to the business assets may have occurred.

To address the policy coverage uncertainty, the Financial Conduct Authority in the United Kingdom (FCA) commenced a test case in June 2020 in the High Court of England and Wales. The High Court rendered a decision in mid-September in a case called *[2020] EWHC 2448 (Comm)*.

The objective of the test case was to obtain a declaratory judgment about the meaning and effect of a representative sample of 19 business-interruption insurance policy wordings (clauses, definitions, exclusions, trends clauses, indemnity limits, etc.) selected from more than 500 relevant policies obtained from 40 insurers.

The relevant provisions of the lead policies essentially fell into three categories.

The first category is disease clauses that provide coverage in cases of business interruption on account of a disease within a specified radius of the insured premises that is notified to a public authority. The key issue was whether the policies provided coverage for the COVID-19 pandemic if the events that led to the business interruption (particularly

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A North Carolina administrative law judge ruled against a mutual insurance company in mid-August that claimed solar tax credits in 2014, 2015 and 2016. The company was hit with a bill for $23.8 million in back taxes, penalties and interest. It invested in a master partnership set up to monetize North Carolina tax credits.

A related case is before a state court.

The cases involve partnerships that Monarch Private Capital organized and syndicated to companies and sophisticated and high-net-worth individuals who invested expecting to be allocated tax credits on solar projects owned by the partnerships.

The state tax department began looking at tax credits claimed by investors in the Monarch partnerships in early 2018. The state ultimately denied the tax credits and, in September 2018, issued a general warning that some partnerships formed to acquire interests in renewable energy projects with the aim of transferring state tax credits to investors are disguised sales of tax credits. Tax credits cannot be transferred through a sale.

North Carolina allowed a 35% tax credit to be claimed on new solar, wind, geothermal, biomass, hydroelectric and combined heat and power equipment through the end of 2016. (Biomass projects had until early May 2017.) Projects that had incurred enough costs or done enough physical work by the deadline were given more time.

The credit had to be claimed ratably over five years on any equipment put to business use. (For more details, see "North Carolina" in the July 2015 *NewsWire*.)

Monarch received a ruling in 2013 approving one of its transactions.

It filed suit in September 2019 against the North Carolina Department of Revenue after failing to persuade the state to drop the audit adjustments. It said it has raised tax equity for 80 solar projects in North Carolina with a value of $900 million.

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## Business Interruptions

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governmental measures) would have happened even without the discovery of COVID-19 cases within a specified vicinity of the business or project site because COVID-19 had occurred or was feared to have occurred elsewhere.

The second category is hybrid clauses that provide coverage in cases where restrictions have been imposed on a business or project premises because of a disease that has been notified to a public authority, but that may not have struck the particular location yet. These types of clauses blend the prevention of access with a general manifestation of the disease.

The third category is clauses that cover business interruptions due to prevention or hindrance of access to or use of the premises as a consequence of government or local authority action or restriction.

Submissions to the High Court were made by the FCA, two intervenors (Hospitality Insurance Group Action and Hiscox Action Group) and the eight insurance company defendants who had agreed to be part of the test case: Arch Insurance (UK) Ltd, Argenta Syndicate Management Ltd, Ecclesiastical Insurance Office Plc, MS Amlin Underwriting Ltd, Hiscox Insurance Company Ltd, QBE UK Ltd, Royal & Sun Alliance Insurance Plc and Zurich Insurance Plc.

The High Court dealt with each insurance policy wording individually, as the court said it was "impossible to determine questions of policy coverage in the abstract."

The court held that most, although not all, of the disease clauses provide cover.

It held that certain prevention-of-access clauses in the samples provide cover, but this depends on the detailed wording of the relevant clause and how the business was affected by the government response to the pandemic, including, for example, whether the business was subject to a mandatory closure order and whether the business was ordered to close completely.

The test case outcome should help both the insurers and insured parties get more clarity on what wording in policies would provide coverage for loss resulting from denial of access resulting from COVID-19 (without any property damage having occurred) and the necessary causation that the insured parties would need to establish in order to succeed in such claims.

The judgment also clarified that the COVID-19 pandemic and the government and public response were a single cause of the covered loss, which is a key requirement for claims to be paid even when the policy provides coverage.

The judgment in the test case is legally binding on the insurers that are parties to the case for how the business interruption insurance policy wordings considered by the High Court are to be interpreted.

The decision may still be appealed by the FCA or the insurers directly to the Supreme Court by "leapfrogging" the Court of Appeal in the United Kingdom.

An application for filing such an appeal to the Supreme Court was made by the FCA on September 28, 2020, as a precaution, in case the FCA and the insurers are unable to reach an agreement on how to process the pending insurance claims based on the High Court judgment.

The appeals process would not prevent insured parties and insurers from settling individual insurance claims in the interim.

The judgment also provides persuasive guidance for the interpretation of similar business interruption insurance policy wordings, which may be relevant to the US insurance market.

The British High Court decided a test case about COVID-related business interruption claims in September.

### Consolidating US Claims

In the US, an attempt was made earlier this year to consolidate the COVID-19-related business interruption and civil authority insurance litigation.

Two petitions were made to the Joint Panel on Multidistrict Litigation (JPML) in April 2020.

One petition sought consolidation of COVID-19 business interruption litigation in a federal district court in

Philadelphia and the other in a federal district court in Chicago.

The advocates for consolidation identified three core common questions. First, do the various government closure orders trigger coverage under the policies? Second, what constitutes "physical loss or damage" to the property? Third, do any exclusions (particularly those related to viruses) apply?

The JPML declined in August to consolidate lawsuits on grounds that these questions shared only a superficial commonality and that there was no common defendant in the lawsuits.

The JPML saw little potential for common discovery across the litigation and noted that the cases involve different insurance policies with different coverages, conditions, exclusions and policy language, purchased by different businesses in different industries located in different states. The JPML said these differences would overwhelm any common factual questions.

However, it said centralization may be warranted to eliminate duplicative discovery and pre-trial practice with respect to four sets of insurers — The Hartford, Cincinnati Insurance Company, various underwriters at Lloyd's of London and Society Insurance Company. These parties were directed to show cause why actions against them should not be centralized.

## Insurers' Response to COVID-19

Several insurers are explicitly excluding COVID-19 from policies that are due for renewal.

Some insurers are reluctant to include an extension under existing insurance policies to cover infectious diseases as many have had legal proceedings commenced against them because of the COVID-19-related claims.

The Lloyd's Market Association (LMA) published a model endorsement or clause in March 2020 — the LMA 5393 communicable disease endorsement — for use to amend the coverage under property insurance policies.

The model endorsement has the effect of carving out losses or damage resulting from "communicable diseases."

The term "communicable diseases" in the model endorsement is broadly defined to include diseases that can be transmitted by a virus through airborne, bodily fluid or surface transmission and can cause or threaten damage to human health or insured property.

Insurers may also take the view that all insurance coverage should exclude any claim that is caused in any way from COVID-19 or any fear or threat of COVID-19. ◎

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Meanwhile, one of the investors — the North Carolina Farm Bureau Insurance Company — was pursuing its own appeal. An administrative law judge decided against the insurance company in mid-August in a case called *North Carolina Farm Bureau Insurance Company, Inc. v. North Carolina Department of Revenue*.

The administrative law judge said the insurance company had invested in state tax credits rather than the underlying solar projects.

The private placement memorandum describing the insurance company transaction said that a master partnership would be formed that would "generate tax credits" from solar projects owned through lower-tier partnerships.

Monarch was the general partner. Investors were expected, as limited partners, to invest an amount per dollar of projected tax credits. There was no guarantee they would receive them, but the partnership kept some of the invested cash in a reserve to return to investors if there was a shortfall in tax credits.

The offering was of master partnership units "in increments of $100,000 of State Tax Credits." Investors would not have to invest any more capital.

The offering took place in September 2014. Monarch had an option to buy back the investors' units during a six-month period starting July 1, 2015 for their fair market value.

Monarch warned investors during the offering that two recent federal court decisions in cases involving Virginia tax credits meant that only part of the investment each investor made in the master partnership would be treated as a capital contribution to the partnership and the rest would be treated as a payment for tax credits.

The federal courts concluded that the investments in the Virginia cases were partly payments for tax credits. They said such payments had to be reported by the partnership promoter for federal income tax purposes as gain from the sale of tax credits rather than as tax-free capital / continued page 19

# Overestimation of Solar Output

*by Richard Matsui, with kWh Analytics in San Francisco*

The solar industry has anecdotally begun raising concerns about whether solar power plants are underperforming compared to their P50 output forecasts.

What began as hushed conversations at industry conferences is now widely discussed and analyzed. Individual engineering firms and asset owners are beginning to review their portfolios to assess whether or not their original P50 forecasts were accurate.

Output from US utility-scale solar projects is 6.3% short on average from the P50 forecast.

DNV GL published a piece in the annual "Solar Risk Assessment" report identifying a 3% to 5% overestimation bias in P50 forecasts, even after adjusting for weather. NextEra published a technical discovery around biases in hourly-resolution energy predictions that overestimate solar resource availability. Behind closed doors, asset owners will also acknowledge struggles to hit P50 figures as consistently as the definition attributes.

## Diving Deeper

Under a P50 forecast, a project is supposed to have a 50% chance of performing at least as forecast. This figure is the base case for the project and is generally the most optimistic projection used in financings. Financiers also run sensitivities by looking at other forecasts — for example, P99 and P90 — as well. A project should have a 99% chance of performing at least at the P99 forecast, if not better.

Generating a production estimate integrates weather forecasting and equipment performance expectations into complex physics models. As with any technical model, results vary based on the assumptions used.

kWh Analytics collaborated with 10 of the top 15 asset owners in the United States to conduct the industry's largest cross-sectional energy validation study, quantifying the accuracy — or inaccuracy — of solar projects' P50 estimate. We looked at data from 30% of the operating utility-scale and distributed solar capacity. The results are reported in an inaugural "2020 Solar Generation Index" report.

Projects on average underperformed by 6.3%, even after adjusting for weather.

This means that actual performance of the US solar fleet is closer to P90 expectations than the P50 definition used by project stakeholders.

It is important to note that while 6.3% underperformance is the average, there is a wide distribution that highlights significant variability among projects. In the bottom quartile, projects are falling more than 10% below forecast while the top quartile performers are meeting their P50 expectations. As a result, we can see that each project is indeed unique, even if the general trend points towards a 6.3% bias.

The issue of energy estimation is not unique to solar. The wind industry similarly struggled to align lenders, owners and operators on expectations around energy output and is still developing tools to address accuracy and biases.

## Implications for Shareholders

If unaddressed for solar, systemic asset underperformance can have serious implications for the equity holder cash flows, investor returns and the long-term financeability and credibility of solar as an asset class.

The impacts are discernible from day 1 of operation.

For an equity investor or sponsor who sits last in line behind the tax equity and debt, P90 performance realities mean equity cash yields are cut in half for the life of the asset. For lenders, given the prevalence of P90 scenarios, underproduction poses a risk to debt coverage.

As a risk management company that enables insurers to provide all-risk production coverage to solar assets, kWh Analytics is also observing this trend firsthand through claims against a "solar revenue put" product that actual output will be at least at a guaranteed level. (For more information about solar revenue puts, see "New product: solar revenue puts" in the October 2016 *NewsWire*.)

To date, insurers have continued to pay all claims in full within 30 days and remain committed to providing sponsors with credit-enhancing insurance products.

However, if unaddressed, inaccurate production estimates and return uncertainty will have long-term consequences for the solar industry.

Every major asset class leverages market data to improve the accuracy and certainty of investment returns. If we look at other mature asset classes like consumer credit or mortgages, companies like Experian and CoreLogic exist to provide market data to validate asset performance and modeling assumptions for investors. Solar is at an inflection point now where we have more than a decade of asset performance data that can be leveraged to inform diligence and improve operating assumptions.

kWh Analytics is using its industry database to offer objective market comparables to evaluate expected yield and performance estimates for pre-construction and operating plants. This new offering, the Solar Technology Asset Risk (STAR) Comparables Report, equips deal teams with historic performance of similar plants to help evaluate performance and financial risk of their projects. In addition, it has helped asset management teams contextualize their portfolio's performance against projects in the field to improve O&M and asset management strategies.

The solar industry has generated the data required to improve the forecasts. The next step is to leverage that data in investment decisions. ◎

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contributions to the partnership. Each investor had to report income equal to the full tax credits less the amount paid for them when the credits were used to offset state income taxes, in the same manner as if the investors had bought property and then converted it to cash and spent the cash. However, the investors could then deduct the state income taxes considered paid in this manner. (For more details, see "A tax credit transaction" in the June 2011 *NewsWire* and "Tax equity deal struck down" in the February 2016 *NewsWire*.)

Most states use federal taxable income as a starting point for their own calculations.

The North Carolina Department of Revenue cited the Virginia tax credit cases in 2018 as grounds for denying tax credits to investors in North Carolina partnerships.

In late August, it called attention to the administrative law judge's decision in a filing in the Monarch court case. The pending court case is *Monarch Tax Credits, LLC v. North Carolina Department of Revenue*.

**ANOTHER PUBLIC UTILITY PROPERTY** ruling was issued by the Internal Revenue Service.

Utilities have been asking the IRS for private rulings that solar projects they plan to develop, buy from developers or put into tax equity partnerships will not be "public utility property."

Utilities have a harder time claiming investment tax credits and accelerated depreciation on public utility property. The projects are public utility property if the rates at which the electricity is sold are established or approved by a utility commission on a rate-of-return basis.

Most of the projects addressed by the rulings are not public utility property because the electricity is sold at negotiated rates.

The IRS released another such ruling at the end of August. The ruling is Private Letter Ruling 202034004.

The utility in question planned to buy a large solar project from a / *continued page 21*

# How to Construct a "Ring Fence"

*by Christy Rivera, in New York*

A key feature of project financings is to "ring fence" a project company from the rest of the businesses of a sponsor.

This ring fencing provides the financing parties with more comfort that the project will not suffer if the sponsor or other affiliated entities begin to falter.

This article explains what ring fencing is, why it is done, how entities have been successfully ring fenced, and what risks and issues should be taken into account when considering whether a subsidiary can or should be ring fenced.

Over the years, ring-fencing structures have successfully protected projects from financial difficulties suffered by their affiliates. For example, when Energy Future Holdings filed for bankruptcy in 2014, its subsidiary Texas transmission company, Oncor Electric Delivery Co., remained outside of bankruptcy, having been ring fenced by EFH years before. When SunEdison filed for bankruptcy two years later, many of the project-company subsidiaries were able to continue operating outside of the bankruptcy case.

Courts look at six factors to decide whether a project has been adequately "ring fenced."

## What is Ring Fencing?

The phrase "ring fencing" refers to steps taken to make a subsidiary "bankruptcy-proof" or "bankruptcy remote."

Ring fencing is supposed to shield the assets of the subsidiary from the bankruptcy of its parent or affiliates and allow the subsidiary to obtain or maintain a "standalone" credit rating substantially higher than the lower credit rating of its parent.

Ring fencing is used in a variety of financing situations, including acquisition financing, monetizing a subsidiary's dividend distributions and corporate spin-offs.  In a project finance context, ring fencing generally refers to implementation of several types of protection. They are limits on the project company's ability to incur debt or engage in business unrelated to the limited purpose of constructing and operating the project, requirements that the entity observe "separateness covenants" — such as maintenance of separate bank accounts and no commingling of assets — and (although less frequently used) a requirement that an independent director or a separate class of stock be established for an entity to vote on voluntary bankruptcy filings.

These types of provisions are implemented in order to guard against certain specific risks in the bankruptcy context, including the following.

One risk is the borrower parent will file a voluntary bankruptcy petition.

Another risk is substantive consolidation. Substantive consolidation is an equitable remedy that allows the bankruptcy court to pool the assets and liabilities of two separate but affiliated entities and to treat them as though they are the assets of a single bankrupt debtor.  While the tests for consolidation differ across jurisdictions, courts generally consider three tests.

The first test is whether creditors dealt with the entities as a single economic unit and did not rely on their separate identities in extending credit. Another test is whether the entities' affairs are so entangled and confused that substantive consolidation will benefit all creditors. A third test is whether consolidation is necessary to avoid some harm or realize some benefit.

Another risk that ring fencing guards against is the filing of an involuntary bankruptcy petition against the subsidiary by creditors of the parent or its affiliates, by creditors of the subsidiary or by the parent or its affiliates.

The final risk is piercing the corporate veil. The "corporate veil" may be pierced if the subsidiary has acted as the "alter ego" of its parent, if the parent exerts more control over the subsidiary than would be expected of a normal investor, or if the actions of the parent directly caused the subsidiary to incur a liability. Piercing the corporate veil is a risk when the parent so disregards the separate identity of the subsidiary that their enterprises are seen as effectively commingled. Creditors could pursue a form of "reverse" corporate veil piercing when the parent is insolvent and the subsidiary is viewed as a source of funds.

## How to Ring Fence

There is no one blueprint that will guarantee that an entity is successfully ring fenced.

However, there are at least six factors at which courts and rating agencies look in order to determine whether an entity is sufficiently "standalone" to justify shielding its assets from creditors of its affiliates (or, in the case of rating agencies, to justify a "standalone", investment grade, rating).

First, the new entity must be a single-purpose entity. Its objects and powers must be restricted as closely as possible to the core activities necessary to effect the structured transaction. This restriction reduces the entity's risk of voluntary insolvency due to claims or risks associated with activities unrelated to the structured transaction. It also reduces the risk of third parties filing involuntary petitions against the entity. These restrictions should be drafted into the entity's charter documents for two reasons: the charter documents are publicly available, and therefore serve as public notice of the restrictions, and the entity's management is more likely to refer to these documents, and therefore be reminded of the restrictions, when conducting its affairs.

Second, the new entity should incur no additional debt beyond what is needed for its routine business purposes. In order to limit the likelihood of an involuntary filing, the entity should covenant not to incur debt except where such action is consistent with its business purpose. This will reduce the likelihood of holders of additional indebtedness pursuing involuntary petitions to gain access to the entity's assets or cash. The entity's charter documents may also contain limits on the entity's ability to incur voluntary liens.

Third, the new entity should covenant not to merge or consolidate with a lower-rated entity. The bankruptcy-remote status of the subsidiary must not be undermined by any merger or consolidation with an entity not adequately protected from bankruptcy or by any reorganization, dissolution, liquidation or asset sale. The new entity should also covenant not to dissolve.

Fourth, the new entity should observe various "separateness covenants" in order to avoid being / *continued page 22*

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project developer under a build-transfer agreement and then use the project to supply electricity to four commercial and industrial customers at negotiated rates.

Any remaining electricity from the project not sold to the four customers would be sold into the wholesale power market.

The state utility commission had to approve the special contracts with the four customers, but not the rates. The amount the utility pays for the project will not be added to its rate base.

The IRS has issued at least four other private rulings about similar arrangements in the last 15 months. (For earlier coverage, see "Renewables and public utility property" in the August 2020 *NewsWire*, "Utility partnership flips" in the June 2020 *NewsWire* and "Solar projects and public utility property" in the June 2019 *NewsWire*.)

It is unclear how many more times utilities will feel the need to hear the same thing from the IRS or the IRS will be willing to repeat it.

The IRS also issued one ruling where a utility plans to put a project into a tax equity partnership that will sell the electricity back to the utility at negotiated rates. The utility will put its investment in the partnership into rate base and pass through the negotiated rate it pays the partnership to its customers as a purchased power expense. (For more details, see "Utility tax equity structures" in the December 2019 *NewsWire*.)

**NEW YORK PROPERTY TAXES** must be paid on a solar project on land owned by Cornell University, a court said.

Cornell leased land in Seneca, New York to a private solar developer, Argos Solar, that put up a solar facility and entered into a long-term contract to sell the electricity to the university. The contract has a term of 20 years. Cornell can extend it for two additional five-year terms — bringing the contract term to 30 years — and can continue the arrangement after that on a month-to-month basis / *continued page 23*

## Ring Fences

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substantively consolidated with its parent. It should maintain separate financial records and financial statements, its own corporate books and records, and separate bank accounts. There should be no commingling of assets with its parent or any of the parent's affiliates. It should pay its own liabilities and expenses from its own funds. It should take steps to correct any misunderstanding about its separate legal nature from affiliates. Entities may also want to consider implementing restrictions on asset transfers and dividend declarations.

Fifth, the company should consider obtaining a "non-consolidation opinion" from its counsel. A non-consolidation opinion addresses the likelihood that a court will grant substantive consolidation based on the observance by a parent and its subsidiary of the various "separateness covenants" referenced above. As part of providing the opinion, counsel will review the transaction structure and documents to ensure that the project is set up and run in a manner that limits substantive consolidation risk.

Finally, the new entity may wish to include in its charter documents either an independent director or a special class of stock (or "golden share"). The independent director or the owner of such class of shares should be an independent entity with no tie or relationship to the parent, its affiliates or any lender to the parent or affiliates. The charter documents of the subsidiary should require the affirmative vote of the independent director or the holder of the golden share before any voluntary filing into bankruptcy. It should also require the independent director or the holder of the golden share consider the interest of the subsidiary's creditors, in addition to the interests of the shareholding parent, when deciding whether to file. This factor is often viewed as critical by the rating agencies in order to insure that a standalone rating for the subsidiary is justified.

These factors are not in and of themselves bullet-proof.

For example, courts will generally not compel compliance with the various covenant requirements. "Non-petition" covenants — under which a parent agrees not to file a bankruptcy petition against the subsidiary — are typically not enforceable, as waivers or prohibitions on bankruptcy petitions are void as a matter of public policy.

Non-consolidation opinions are fact specific, limited in scope and highly qualified; they also do not address the likelihood of the parent independently filing the subsidiary into bankruptcy.

The "golden share" or independent director mechanism only addresses a voluntary bankruptcy situation and may be of limited benefit. In some cases bankruptcy courts have invalidated "golden-share" provisions in a company's organizational documents and allowed the company to file for bankruptcy.

While the independent director or golden shareholder may reduce the risk of a voluntary bankruptcy petition, the risk that creditors will pursue an involuntary filing still exists. As a result, an entity should consider incorporating as many of the elements listed in this article as possible when contemplating a restructuring with the intent of ring fencing. (It should probably also opt for the independent director approach rather than the golden-share approach.)

### When to Ring Fence

Ring fencing is often perceived by the public as an attempt to hide assets that would otherwise be available to creditors.

However, the companies doing the ring fencing suggest that they are restructuring their assets to maintain the viability of the company.

The difference between hiding and restructuring may depend in part on timing — for example, whether the new entity was in place before or after the liabilities were incurred. Although this element has not yet appeared as a factor in the court's decision-making process, companies would be wise to begin the restructuring and ring-fencing process as soon as practicable, before financial problems arise that make such a restructuring a necessity as opposed to just good business sense. ◎

# Products for Corporate Offtakers

*by Christine Brozynski, in New York*

Companies that are parties to virtual power purchase agreements may find themselves taking on more risk than they had originally anticipated.

The extra risk can be mitigated by two products designed by REsurety, working with Allianz and Nephila Climate: a volume firming agreement and a settlement guarantee agreement.

## Risks

Companies often sign virtual power purchase agreements — called VPPAs — to meet internal clean energy goals.

Buying undifferentiated electricity from the grid does not work, and many companies find it difficult to purchase energy directly from renewable energy projects.

A VPPA is a way around that. It is called a "virtual" power purchase agreement because there is no physical delivery of electricity. It is a financial instrument that acts as a hedge for both the corporate offtaker and the renewable energy project on the other side of the trade. It may also provide another revenue stream to a project developer because corporates often buy the renewable energy credits to which the project is entitled.

VPPAs are typically structured as contracts for differences. A contract for differences is a type of financial hedge whereby the offtaker pays a fixed price and the project company pays a floating price that is linked to either the price at the node (the place where the project interconnects with the grid) or the hub price. The contract settles on the actual amount of electricity produced by the project.

As an example, let's assume the fixed price is $20 a megawatt hour and that the VPPA settles at the node. (The node is a location on the electricity grid.) In hour one, the project produces 10 MWh of power that are sold at the node for $20 a MWh. In hour two, the project produces 15 MWh of power that are sold at the node for $25 a MWh. In hour three, the project produces 30 MWh of power that are sold at the node for $10 a MWh.

In this example, neither party owes the other party anything in hour one, as the nodal price matches the fixed price. In hour two, the project company owes the corporate $75 because the nodal price is higher than the fixed / continued page 24

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by continuing to take and pay for the electricity.

The developer argued that it should not have to pay property taxes on the project.

A New York superior court agreed. It said the solar facility was not "real property" and, moreover, the university had "beneficial ownership" of it. Universities, like Cornell, are not subject to property taxes.

The appellate division of the superior court disagreed.

The New York property tax statute defines "real property" as "[b]uildings and other articles and structures, substructures and superstructures erected upon, under or above the land, or affixed thereto."

The court said whether the facility is permanently affixed to land does not turn on how easy it would be to remove it, but rather whether the parties intend for it to remain in place "permanently over the life of the agreement." The facility has nearly 1,600 piles driven directly into the ground and another 400 embedded in concrete footers. Racks of solar panels are bolted to the piles, and an inverter and other equipment are on a concrete slab.

The court also said the private developer, not Cornell, is the facility owner.

The case is *Cornell University v. Board of Assessment Review*. The court released its decision in late August.

The solar company should have explored a PILOT lease arrangement as a way to reduce property taxes. Under such arrangements, title to a project is put in municipal hands and then an amount of "payments in lieu of taxes" is negotiated with the municipality.

**HAWAII** is cancelling a 35% tax credit for solar projects that are five megawatts or larger in size and that have power purchase agreements that must be approved by the public utilities commission.

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## Corporate PPAs

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price, and that upside is passed along to the corporate (($25 x 15 MWh) - ($20 x 15 MWh) = 75). In hour three, the corporate owes the project company $150 because the nodal price is lower than the fixed price, and the corporate provides downside protection (($15 x 30 MWh) - ($20 x 30 MWh) = -150).

Typically, corporates enter into VPPAs in an effort to buy virtual electricity for a specific spot. For example, if a corporate has a data center in Texas, that corporate might enter into a VPPA settling at the hub closest to the data center. (The hub price is a liquid trading price determined by the regional transmission organization that manages the electricity grid based on nodal prices in the area.) In an ideal world, the VPPA would settle on an amount of power that approximates the data center's usage.

The problem is that VPPAs settle on the amount of power produced by the project, not the amount of power used by the corporate.

Wind and sunlight are variable resources. On a windy day, the volume of power on which the VPPA settles may be far greater than the power used by the corporate offtaker; the converse may be true on a relatively windless day.

Because of this variability, the corporate offtaker is taking on shape risk (the risk that the times at which the project produces power do not align with the times at which the corporate uses power) as well as volume risk (the risk that overall production at the project over a period of time is either greater or less than overall electricity usage by the corporate).

Two products – a volume firming agreement and settlement guarantee agreement – are designed to mitigate some of that risk.

### Volume Firming Agreement

Volume firming agreements are designed to "shape" the amount of power on which the VPPA settles in order to better align the transaction with the corporate's electricity usage.

A volume firming agreement is a separate transaction entered into between the corporate and an insurance company or weather-risk investor that can be entered into concurrently with or at any time after execution of the VPPA. The project company is not involved with and, is typically not required to be made aware of the existence of, a volume firming agreement.

To understand how a volume firming agreement works, return to the example of a corporate that has entered into a VPPA to offset electricity usage at a data center near the project. A volume firming agreement lets the corporate craft a fixed shape that more closely resembles its power usage at the data center.

A fixed shape in this context is a chart with the months listed in the first column and the hourly quantity for each month in the second column. For example, if in January the corporate anticipates that its data center will consume an average of 10 megawatts of power per hour, then the number next to January will be 10.

The volume firming agreement operates like a slightly more complicated version of a contract for differences with respect to each hour, with the corporate owing one floating amount per hour and the counterparty owing a different floating amount per hour. The two floating amounts are netted for all hours across a calendar quarter, and the result is the settlement amount that one party pays to the other.

The corporate floating amount is structured to reflect the settlement under the VPPA. If the corporate owed money to the project company for a given hour under the VPPA, then the corporate floating amount under the volume firming agreement is the same dollar amount. If the corporate is owed money by the project company for a given hour under the VPPA, then under the volume firming agreement, the corporate floating amount is negative of that dollar amount.

There is one important nuance to the corporate floating amount, however. It does not track the VPPA settlement perfectly; rather, it reflects what the VPPA settlement would have been if the wind turbines or solar panels at the project had operated at a pre-determined fixed rate of efficiency. This revised electricity output is referred to as the proxy generation. It is a means of safeguarding the volume firming agreement counterparty from operating risk, which encompasses everything from mechanical issues with the turbines or panels to improper operation of the power plant by the project company.

The counterparty floating amount for each hour is calculated as the market price minus a "fixed volume price" per megawatt hour, the remainder of which is multiplied by the quantity for that hour in the fixed-shape schedule. The fixed volume price is negotiated between the corporate and the counterparty.

The settlement entails netting the corporate floating amount with the counterparty floating amount. Because the corporate is paying a floating amount based on the VPPA settlement and receiving a floating amount based on the fixed shape, the volume firming agreement has the effect of shaping the power for the corporate.

The end result for the corporate is that the combined volume of power on which it settles under the VPPA and volume firming agreement is roughly the amount of power used by the data center, office building or other electricity-consuming structure for which the VPPA was initially designed.

## Settlement Guarantee Agreement

Unlike a volume firming agreement, which is designed for corporates that want to shape their power, a settlement guarantee agreement is designed for corporates that want to lock in a fixed cost with respect to a VPPA. For example, if a corporate enters into a 12-year VPPA designed to offset electricity usage at a data center that unexpectedly shuts down in year five, the corporate may wish to reduce its risk for the remaining life of the VPPA by exchanging gains and losses under the VPPA for a fixed price.

The settlement guarantee agreement is structured like a contract for differences with a corporate floating amount and a counterparty floating amount. The corporate floating amount is the same as in a volume firming agreement. In other words, it the same floating amount that the corporate receives or pays under a VPPA, adjusted for proxy generation.

The counterparty floating amount is different: it is simply a fixed lump sum per quarter. The lump sum is negotiated when the settlement guarantee agreement is signed.

If the corporate floating amount (designed roughly to reflect the amount paid or owed by the corporate under the VPPA) exceeds the lump sum, then the corporate pays the excess to the counterparty. If the corporate floating amount is less than the lump sum, then the counterparty pays the difference to the corporate.

In this way, the corporate is able to pass through a significant amount of risk it faces under the VPPA to the counterparty under the settlement guarantee agreement.

A corporate would not enter into both a volume firming agreement and a settlement guarantee agreement with respect to the same VPPA.

Entering into a second product would be expensive for the corporate and would not offer any incremental benefit to the corporate, as the risk would already be mitigated with the first product. If a corporate that is party to a volume firming agreement wishes several years later to enter into a settlement guarantee agreement, that corporate would probably terminate the volume firming agreement first. ◎

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The repeal is effective retroactively to tax years beginning after 2019.

However, it does not apply to two types of projects.

Projects whose power purchase agreements were approved or were awaiting approval by the commission before December 31, 2019 can still claim a tax credit.

Solar projects that are coupled with hydro-electric pumped-storage systems have until the end of 2021 to apply for approval and claim tax credits.

The tax credit amount is capped at $500,000 per megawatt of capacity.

The Hawaii governor signed the bill in mid-September. The repeal is a cost-cutting measure.

**PAYMENTS INTO A STATE FUND** to pay for wildfire damage can be amortized for US tax purposes over 15 years, the IRS said.

The agency made the statement in a private letter ruling issued to a utility that it made public in mid-September. The ruling is Private Letter Ruling 202037001.

The ruling describes a program that sounds like one adopted by California to place a cap on the amount that California electric utilities can be required to pay for damage from wildfires.

The state set up a fund in 2019 that is funded from two sources. The three investor-owned utilities agreed to make initial contributions of $7.5 billion. Grid users are contributing another $900,000 a year for 15 years through a special charge on utility bills.

The fund is used to pay damage claims from wildfires on or after July 12, 2019 that the state finds were caused by a utility. The utility has the first loss. The fund is not tapped until after a utility retention amount is paid.

The utilities must contribute another $300 million a year for the next 10 years. The private letter ruling said the actual contributions will depend on need.

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# Depreciation Bonus Questions Answered

*by Keith Martin, in Washington*

Depreciation bonus regulations that the Internal Revenue Service issued in September 2019, and then tweaked in September 2020, answer a number of questions that have been coming up in M&A and tax equity transactions.

## Background

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

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

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

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

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

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

A depreciation bonus has been available at different levels since late 2001. Most tax equity investors have been uninterested in claiming it, except in 2017 when Congress was expected to reduce the corporate tax rate and investors tried to accelerate deductions to take them against the high rate. Tax equity investors would rather spread their scarce tax capacity over more projects than use up tax capacity immediately as deals close.

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

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

M&A issues

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

Many projects in the power and other infrastructure sectors are owned by limited liability companies that are treated as partnerships for US tax purposes.

**Buyers may be able to deduct part of the purchase price for a joint venture interest immediately as a depreciation bonus.**

In addition, most tax equity raised in the renewable energy market takes the form of partnership flip transactions. (For more information, see "Partnership flips" in the April 2017 *NewsWire*.)

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

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

The step-up depreciation is considered depreciation on used property if the project was already in service. A bonus can be claimed on used property, but not if the buyer owned an interest in the property earlier. The IRS does not look through a partnership for this purpose. Thus, for example, a partner who has a 30% interest in a partnership that increases to 50% by buying an additional interest from another partner can claim the bonus on any step-up depreciation on the additional 20% interest. The buying partner must not have owned the partnership assets directly before they were put in the partnership within the last five years. The buying and selling partners cannot be affiliates.

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

## Tax equity issues

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

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

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

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California has an "inverse condemnation" law holding utilities strictly accountable for damage caused by their power lines and other equipment. The safety certificate entitles the utility to a presumption that it behaved prudently. If it is later found to have behaved imprudently, then the utility must reimburse the fund up to a cap. Otherwise, no reimbursement is required. (For more details about operation of the California wildfire fund, see "California moves forward" in the October 2019 *NewsWire*.)

A company setting aside money to pay future claims is usually not allowed to deduct the amount until the claim is paid.

In this case, a utility argued that its initial contribution was essentially purchase price for a type of intangible property right called a "section 197 intangible." Such intangibles include "any license, permit, or other right granted" by a government agency.

The cost of section 197 intangibles is deducted on a straight-line basis over 15 years.

The IRS agreed. The deductions started immediately.

The IRS said the additional annual payments are effectively additional contingent purchase price for the intangible and can be deducted on a straight-line basis over the remainder of the 15-year period.

**THE US JUSTICE DEPARTMENT** said in August that a $237,000 fee that a US fund manager planned to pay an investment bank owned by a foreign government for help with an acquisition would not trigger prosecution under the Foreign Corrupt Practices Act.

The Foreign Corrupt Practices Act makes it a crime for US companies and citizens to give 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 an improper advantage.

The US fund manager acquired a portfolio of assets from the country A office of a foreign investment bank. The */ continued page 29*

## Depreciation Bonus

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However, the depreciation bonus works differently in one situation. That situation is where one of the partners owned an interest in the project before the project is contributed to the partnership and the project is first put in service and then contributed to the partnership in the same tax year it went into service. In that situation, the depreciation bonus for the project (or in a wind project, an individual turbine, pad and tower put in service before its contribution) will be split among the partnership and the contributing partner based on the number of months each owned the project or turbine in the year it is placed in service. It is complicated if the contributing partner and the partnership have different tax years. Depreciation allocated to the month in which the partnership is formed belongs to the partnership.

The depreciation bonus will start to phase out after 2022.

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

Putting these two principles together, suppose a tax equity investor comes into a project by paying the developer directly for an interest in the project after the project is in service. The developer would not be able to claim any depreciation on the share of the project considered sold to the investor. The investor should be entitled to a bonus even if the project was already in service. A bonus can be claimed on used property. However, any such bonus would remain with the investor outside the partnership. The investor is considered to buy and immediately contribute an undivided interest in a project that is already in service. (However, if the project was originally put in service in the same month these transactions occur, then the bonus may belong to the partnership.) The partnership takes the asset with a zero basis and with a "built-in gain" that leads to something called section 704(c) adjustments inside the partnership. Section 704(c) adjustments are discussed below.

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

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

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

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

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

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

The regulations also address some issues in leasing transactions.

Regulated utilities are not allowed to claim a depreciation bonus on equipment used to supply electricity or services at regulated rates of return. People ask what happens if the utility sells and leases back equipment to a tax equity investor: can the lessor claim a bonus? The answer is yes. The lessor cannot be a regulated utility itself.

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

Finally, wind and solar companies have been racing to start construction of projects ahead of deadlines to qualify for federal tax credits. One way to start construction is to start "physical work of a significant nature" on the site or at a factory on equipment for the project. Any such work must not start before a binding contract is in place for the work. People ask whether it is enough that the contract is binding on the developer or whether it must also be binding on the construction contractor or equipment vendor. The IRS said a contract is not considered binding for depreciation bonus purposes unless it is binding on both. ◎

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bank was owned 50% plus one share by a foreign government.

The US fund manager initially hired the country B office of the investment bank to advise it on the acquisition, but when the deal languished, it hired a local partner in country A to push the transaction across the finish line.

The country B office later approached the fund manager about paying it a fee. No agreement was signed requiring a fee. The country B office wanted 0.5% of asset value.

The fund manager asked the US Department of Justice whether the payment would get the fund manager into trouble under the Foreign Corrupt Practices Act.

The Justice Department said no. Even if the employees of the country B office are all considered foreign government officials, the payment was to the government entity itself and not to any individuals. There was no evidence the payment would be passed to any individuals. The US fund manager represented that it sought and received legitimate analytical and advisory services from the country B office in connection with the deal.

This is the first advisory letter that Justice has issued under the Foreign Corrupt Practices Act in six years. The document is FCPA Advisory Opinion 20-01. The letter took at least nine months to obtain.

*— contributed by Keith Martin in Washington*

# Powering Data Centers

*by Marissa Leigh Alcala and Rachel Rosenfeld, in Washington*

Technology companies with significant data center operations are responsible for more than 16,600 megawatts of the approximately 26,000 megawatts of total renewable capacity contracted for under corporate power purchase agreements in the United States to date.

Data centers are physical facilities where equipment is centralized for the purpose of storing and allowing access to large amounts of data.

In 2018, the world's data centers consumed about 1% of all electricity consumed that year worldwide. The percentage has remained more or less constant despite the increase in number of data centers, and the increase in volumes processed at existing data centers, as data centers are becoming more efficient energy users.

Many data-center companies feature prominently in carbon neutrality and other similar initiatives.

The RE 100 initiative is a global initiative by companies committed to taking 100% of their energy from renewable sources. As of this year, the initiative has 260 members, including key data-center owners and users like Apple, Amazon, eBay, Equinix, Facebook, Google, Iron Mountain and SalesForce.

The top-10 EPA Green Power Partner list is a voluntary program that supports corporate procurement of green power and has a number of additional prominent data-center owners as participants, including Cisco, Digital Realty, Intel, Microsoft, Switch, and T-Mobile.

## Siting Considerations

Availability of renewable energy from the grid where a data center is planned can be a key factor in data-center siting.

Climate and geographic stability are more critical for a data center than for other buildings. Any interruption in service, no matter how brief, is a major issue for both the data center and its clients who rely on immediate access to stored data.

Data centers need to avoid flooding, tornados and hurricanes, excessive heat and seismic activity. The same conditions can contribute to potential instability of the power grid.

Road access to a data center site is also particularly important in the event emergency access is needed. Data-center owners look for sites with multiple points of access on top-quality paved and maintained roads. This is usually not an issue in major metropolitan areas, but can present challenges in rural areas.

In addition to traditional utility access, data centers provide better service if they are close to strong internet exchanges and fiber networks. The strength of the connection to fundamental data infrastructure is a more important factor in data center reliability and speed of service when compared to the distance from the data end user.

The "edge" remains a factor in data-center siting. The word "edge" refers to the location of end users of data stored in or passing through data centers. The edge is a moving target. The volume of data usage for social and consumer purposes continues to grow. Commercial data usage fluctuates between traditional downtown or corporate office park locations and work-from-home or other remote locations. This affects the ideal location for a data center, as proximity of a data center to end users of its data can lead to increased efficiency in demand-response time.

Security concerns also loom larger for data centers than for other commercial undertakings given the sensitivity of the data stored as well as the crucial need for uninterrupted delivery of services. Data-center developers closely examine the overall security of a proposed data-center site.

Some data-center owners have considered co-siting with a power plant whose electricity output would be dedicated, in whole or in part, to the data center. There is a debate about whether the potential increased security concerns from having the power plant and data center so closely linked outweigh the benefits of a dedicated nearby power source.

Data-center users look for scalability, meaning the ability to increase the square footage leased in a particular data center while the data-center owners look for the opportunity to build additional data centers near the same footprint.

## PPAs

Electricity is one of the largest operating expenses for a data center.

Only the smallest leases, generally using less than 50 kilowatts of electrical capacity, would normally include power as part of the lease payment. In larger leases, the data-center tenant must usually pay separately for the electricity it consumes.

Many data centers enter into corporate power purchase agreements directly with renewable energy suppliers. These are often "virtual" PPAs, meaning financial instruments to manage electricity costs rather than direct purchases of the physical electricity. A virtual PPA is essentially a form of price hedge, where a price is agreed and payments are made between the parties to the PPA depending on whether the contracted price for power is above or below the market price. Other data centers contract with "sleeved" PPAs, where the utility company acts as an intermediary on behalf of the data center, as power purchaser, handling the transfer of electricity from a renewable energy project to the data center (and the payment from the data center to the renewably energy project).

As of 2019, Google and Facebook were the largest corporate buyers of renewable energy in the world. Both are taking steps to eliminate all carbon emissions from their footprints by 2030, both for direct emissions and their entire supply and value chains. Amazon aims to use 100% renewable energy by 2025 and reach net-carbon-zero operations by 2040.

Some tech giants also engage in innovative practices to increase their actual (and not simply virtual) use of renewable energy. Google uses a carbon-intelligent computing platform to schedule large computing jobs at times when the power consumption can be fully covered by renewable energy (for example, from solar during daytime hours).

Long-term demand by the largest technology companies is also supporting bespoke arrangements.

Enel signed a PPA with Facebook and Adobe for its 320-megawatt Rattlesnake Creek wind farm in Nebraska in 2018. Under the agreement, Adobe purchases 10 megawatts of capacity from the plant between 2019 and 2028, and then the purchase obligation is transferred to Facebook to supply an expansion of its data center in Nebraska.

Other arrangements used by data centers include aggregated PPAs (where various entities join together and sign one PPA), anchor and joint-tenancy arrangements, where one anchor tenant signs a PPA for a significant amount of the electricity produced by a project and smaller purchasers buy the remaining power generated, and dividing up and reselling an existing PPA.

In scenarios where Facebook and Microsoft have served as an anchor tenant (signing their own PPAs for a large portion of electricity generated by a particular project), the smaller buyers of the remaining electricity must still demonstrate creditworthiness. Due to the comparatively small percentage of the offtake, it may be easier for a smaller buyer to contract with lower credit or for a shorter contract length.

When the offtaker is a data center leasing to tenants, and not itself the sole or majority user of a data center, then the credit risk that must be analyzed is that of the tenants.

## Other Arrangements

Another mechanism for crediting use of renewable energy to data centers is the use of renewable energy certificates or RECs.

Various US states have "renewable portfolio standards" that require utilities to supply a certain percentage of their electricity from renewable sources. The utility or other company generating the electricity receives RECs. Utilities must turn in RECs at year end representing the amount of renewable energy they are required to supply. They get RECs either by generating the electricity themselves or by buying them from independent generators. Data-center owners may voluntarily purchase RECs in order to meet their own sustainability goals and internal requirements.

A company that generates renewable energy, but does not own the associated RECs, could announce that it generates renewable electricity that it sells to another party, that it helps to green the grid, or that its sale of RECs helps a utility or other company fulfill renewable energy targets, but only the REC purchaser receives credit for use of the renewable energy. The purchase of RECs might offset the non-renewable resources providing actual power to a facility.

Major data-center players have worked with local utilities to create new green tariffs before deciding to build a data center in a particular service territory.

Utility green tariffs are sleeved PPAs in regulated markets, meaning optional programs offered by utilities that allow larger customers to buy bundled renewable electricity from a specific project through a special utility tariff. These tariffs are gaining popularity in US regulated energy markets where vertically-integrated utilities make it difficult for corporations to procure power from renewables projects directly. (Customers are limited to whatever renewable power is offered by the local utility.)

As of November 2019, 31 green tariffs have been approved or are pending approval in 18 states: Colorado, Georgia, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, Nevada, New Mexico, North Carolina, Oregon, South Carolina, Utah, Virginia, Washington, Wisconsin, and Wyoming. Some of these states have more than one green tariff program.

Facebook built a 970,000 square-foot data center in Utah powered by a new green tariff it developed with Rocky Mountain Power in 2018. In Alabama in 2018, Facebook worked with the Tennessee Valley Authority to create a renewable energy tariff that will allow Facebook and other customers to purchase clean and renewable energy.

Sometimes there are existing utility / continued page 32

## Data Centers

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programs through which companies can buy green energy. For example, Facebook worked with Pacific Power to use a "schedule 272 tariff" to support the Prineville data center with 100% new solar energy in 2018.

### Who Gets Credit?

An enterprise data center is a data center owned and operated by the sole user and is often built on or near the company's corporate campus.

Large companies such as Apple, AWS, Google, and Microsoft regularly build and operate their own data centers. For enterprise data center owner-operators, the same company that purchases power is the ultimate end-user of that power, and has a clear claim to any credit for using renewable energy at the data center.

In a co-location data center, a data center owner leases full-service space within a single data center to multiple customers.

Managed data centers have the data center owner leasing the entire data center building to a single customer.

In these scenarios, it can be hard to determine who should be able to claim the credit for renewable energy purchased for that data center. There are multiple tracking systems and various states have designed rules to prevent double counting of electrons by more than one entity. The most common approach has been for the facility operator, who is the direct purchaser of the power, to claim any such credit.

In 2019, Iron Mountain, a data center provider, launched a "green power pass" reporting program. Under that program, Iron Mountain will provide an annual certificate to its data center tenants confirming (where applicable) that 100 percent of the power a tenant uses at its data center is from qualifying renewable resources. Participating tenants also receive detailed reports about their power consumption and full documentation of the amount, source and chain-of-custody of the wind, solar or other renewable electricity purchased for the data center.

As an example, the data center operator generally controls the cooling of the facility, while the tenant controls the power used for its IT load. Application of this reporting program would separate power used for cooling from power used for IT load. This approach allows both the data center owner and tenant to get credit for renewable energy use toward their corporate sustainability goals.

### Virginia and Texas

Up to 70% of the world's internet traffic flows through Virginia data centers. Virginia is the largest data-center market in the world with more than 10.8 million operational square feet.

Virginia is a popular data center location due to favorable tax incentives, access to the MAE-East internet exchange point (one of the most important pieces of physical infrastructure for content delivery and exchange of internet traffic), its sizeable population, skilled workforce, and inexpensive land.

Amazon owns or leases a substantial number of data centers in Virginia, as do Facebook, Microsoft and many other tech companies.

Northern Virginia has more data centers than the sixth through the 15th largest markets combined (New York Tri-State, Atlanta, Austin-San Antonio, Houston, Southern California, Seattle, Denver, Boston, Charlotte-Raleigh and Minneapolis) and almost as much as the second through fifth largest markets combined (Dallas-Fort Worth, Silicon Valley, Chicago and Phoenix).

Most renewable capacity in Virginia (approximately 1,700 megawatts) is contracted in corporate PPAs.

Facebook is the largest buyer with 562 megawatts of contracted capacity. Other notable buyers are Amazon with 452 megawatts, Microsoft with 335 megawatts, T-Mobile with 178 megawatts and Apple with 134 megawatts. While wind power, particularly offshore wind, is expected to gain traction in Virginia, all of the corporate contracted capacity in Virginia to date is from solar projects.

Virginia is a growing renewable energy market. The state enacted a "Virginia Clean Economy Act" in April 2020 that requires utilities to supply 30% of their electricity from renewable sources by 2030, increasing to 100% by 2050.

The state has set a target of 5,200 megawatts of offshore wind.

The Virginia Clean Economy Act has a schedule for Dominion Energy and American Electric Power to build new renewable power plants or sign contracts to buy power to replace carbon-emitting plants that will shut down. Dominion Energy committed to 3,000 megawatts of renewable energy by 2022 and has plans to add approximately 5,100 megawatts of offshore wind and 16,000 megawatts of solar through the end of 2035.

Renewable power may become a common part of the "turnkey" offering for data-center operators leasing data-center space.

Digital Realty, a data-center operator, procured 80 megawatts of solar power on behalf of Facebook in 2019 for its data centers in northern Virginia in a back-to-back utility-scale transaction where the data center enters into a virtual power purchase agreement to supply renewable energy to a particular tenant in its data center. The deal helps Facebook reach its goal of global operations with 100% renewable energy by the end of 2020. In 2019, 86% of Facebook's operations were run using renewable energy.

Texas is another large US market for data centers.

The Dallas-Fort Worth metro area is the second largest metropolitan market in the US, with approximately 4.3 million square feet of net operational space in 2020. Austin and San Antonio also host significant volumes.

In 2020, Texas leads the country in overall renewable energy capacity as well as in cumulative signed corporate PPAs. High wind resources, easy permitting procedures and federal tax credits have made Texas a lucrative market for wind developers, and its affordable land and sizeable population make it an attractive location for data center development.

Texas exempts various items necessary for data-center operation (such as electrical systems, cooling systems, emergency generators, data storage devices, etc.) from sales and use taxes.

As of 2020, data-center players Amazon, Apple, Digital Realty, Equinix, Facebook, Google, Microsoft and QTS have signed corporate PPAs with renewable energy projects in Texas for a combined capacity of more than 2,000 megawatts. Both wind and solar are well represented in these projects.

## Latin America

The data center market in Latin America is expected through 2023 to grow at a compound annual rate of 11.49% and reach revenues of more than $1 billion.

In addition to the standard siting concerns, data-center owners building in emerging markets focus on the overall business climate, growth potential and stability of a country.

Brazil leads Latin America in number of data centers. Chile has also been a popular site for data centers, especially in view of the new submarine fiber-optic cables connecting in Chile.

Some Latin American data centers buy electricity directly from renewable energy suppliers. By 2025, as much as 27% of data-center power in Latin America will come from solar and wind power and 29% from hydroelectric power.

Some companies are already powering their data centers entirely with renewable energy. For example, since 2017, Google Chile has procured 100% of its electricity from renewable energy, by way of a direct purchase of power from the El Romero solar plant in the Atacama desert, built and operated by Acciona.

Corporate PPAs are growing in popularity. In 2019, companies across Latin America purchased 2,000 megawatts of clean energy using such PPAs, tripling the amount they purchased the previous year.

## Energy Efficiency

Advances in energy efficiency make it hard to predict how a data center's power needs will change over the life of the facility.

Overall data center design has also been changing. While many data centers are single-story buildings, reduction in heat generated by racks and other equipment, increased efficiency in cooling technologies as well as increased efficiency in energy consumption, has made multi-story buildings more viable.

Data centers use power monitoring tools to identify power consumption trends inside the data center. Monitoring may lead to reconfiguration of racks within a data center to even out power consumption across the space, reduction in areas of higher heat, or shifts in certain non-critical energy-intensive activities to off-peak periods. As monitoring technology improves, energy efficiency efforts should bear even more fruit.

Data centers employ back-up power and storage for an uninterruptible power supply. Failures of older valve-regulated lead-acid batteries currently used for uninterruptible power supply have been the most significant cause of unscheduled outages. Data centers have been transitioning to lithium-ion batteries. Lithium-ion batteries can function reliably at higher temperatures, recharge faster and fit in smaller physical spaces, and they last longer and are more reliable. ◎

# Environmental Update

California Governor Gavin Newsom signed a broad executive order in September that sets a goal of requiring all new passenger vehicles sold in the state to have zero emissions starting in 2035. It also asks the state legislature to block issuance of hydraulic fracturing permits by 2024.

Newsom called attention to the widespread wildfires consuming large swaths of California and said "This is the most impactful step our state can take to fight climate change."

The executive order directs the California Air Resources Board to issue regulations requiring all new passenger cars and trucks sold in the state by 2035 to be zero-emission vehicles.

CARB is already working on regulations that are expected to require all medium- and heavy-duty trucks on California roads be 100% percent zero emission by 2045, where feasible.

The order also requires state agencies to accelerate placement of fueling and charging stations around the state in partnership with the private sector. The state cannot move to electric and hydrogen vehicles without such infrastructure.

Californians can still own gasoline-powered cars, and there is no restriction on buying and selling such vehicles in the used-car market.

A press release that the state issued says that "zero-emission vehicles will almost certainly be cheaper and better than the traditional fossil fuel powered cars" by 2035. "The upfront cost of electric vehicles is projected to reach parity with conventional vehicles in just a matter of years, and the cost of owning the car - both in maintenance and how much it costs to power the car mile for mile - is far less than a fossil fuel burning vehicle."

Newsom does not have authority to ban fracking by executive order. The state legislature would have to act.

## Forever Chemicals

A class of chemicals under increasing regulatory scrutiny at both the federal and state levels should be on the radar screen of project developers to avoid getting caught up in someone else's mess when selecting project sites.

Per- and polyfluoroalkyl substances, or PFAS (pronounced "PeeFAS"), are a broad group of fluorinated chemicals that have been widely used in the United States and around the globe following their introduction in the 1940s.

Regulation is still nascent, but is already expanding rapidly, particularly at the state level, with indications that additional federal regulation is likely.

EPA and other regulators suggest that the chemicals can build up in people's bodies through drinking water and other types of exposure and that this can cause reproductive and developmental, liver, kidney and immune-system problems if there is enough exposure over time. Drinking water exposure is the focus of most regulatory concern so far.

PFAS are commonly added to a variety of consumer products to make them non-stick, waterproof and stain-resistant or to make them more effective as a firefighting agent.

They are sometimes referred to as "forever chemicals" because their durable chemical makeup not only makes them highly beneficial for such uses, but may also make them more resistant to degradation and treatment when released into soil or groundwater.

PFAS have been used in the manufacture of products such as carpets and upholstery, waterproof apparel, floor waxes, non-stick cookware, camping gear, fast-food wrappers, cleaners, dental floss and firefighting foams for putting out fuel fires.

While the main regulatory exposure is likely to fall on manufactures of PFAS themselves or of the products that contain PFAS, risk could arise in any situation where PFAS-containing products have been used in such a way that the chemicals are released into the environment at or near project sites.

Somewhat common examples of potential areas of concern include prospective solar sites where fire-fighting training has been conducted, such as on municipal property or at or near current or former airports and on military bases. If PFAS-containing foams were used in training, particularly over a long period of time, the risk of contamination should be vetted, particularly if the developer will own the site.

Another example is putting a solar array on a landfill in which such materials may have been deposited. Whether or not a landfill has reached regulatory closure, it is unlikely that such closure took into account potential PFAS contamination and all or most such regulatory closures have reopener provisions.

For developers selecting project sites, and for lenders or investors deciding whether and on what terms to lend or invest, the likely expansion of regulation should be kept in mind when negotiating contract terms defining the scope of environmental disclosures and allocating environmental risks and when reviewing environmental site assessments and other diligence materials.

Whether a project company will own a site with potential PFAS contamination, as opposed to leasing or being granted an easement to use the site, is also a paramount consideration.

Although a project company is not out of the woods as a potential operator or as a cause of a release or for exacerbating a release under certain federal and state environmental laws, leases and easements generally avoid or limit claims that the project company should share in liability for historical releases barring certain circumstances.

The goal of conducting a phase I environmental site assessment of a project site before entering into a transaction is to identify "recognized environmental conditions" as part of diligence.

## Coming Regulation

A "recognized environmental condition" is "the presence or likely presence of any hazardous substances or petroleum products in, on, or at a property: (1) due to any release to the environment; (2)under conditions indicative of a release to the environment; or (3) under conditions that pose a material threat of a future release to the environment."

Sometimes performing a phase I environmental site assessment can help a party qualify for certain defenses to Superfund liability. A timely and full phase I assessment is a necessary precursor for having conducted the "all appropriate inquiry" that is needed to qualify.

Look for PFAS contamination when selecting project sites.

If a party qualifies for a defense under Superfund, that does not necessarily mean it is shielded from state or common law liability exposure. Market practice is to perform the phase I assessment to the ASTM E1527-13 standard, but this does not, by its own terms, "address requirements of any state or local laws" and even excludes some federal laws. As the standard warns, "[u]sers are cautioned that federal, state, and local laws may impose environmental assessment obligations that are beyond the scope of this practice."

Whatever legal or factual defenses are available, they also do not shield a project company from being pulled into a lawsuit, particularly where groundwater contamination threatens area drinking water wells or the landowner or other responsible parties are insolvent and the project company is the only deep pocket in sight.

PFAS are not currently regulated as "hazardous substances" under the federal Superfund statute, the Resource Conservation and Recovery Act or the Safe Drinking Water Act.

Since what constitutes a "hazardous substance" under the ASTM standards is limited to how the term is defined under various current federal environmental laws, parties doing diligence have to pay attention to emerging chemicals that may be tomorrow's federal regulatory concern or that may currently raise state or even local law risk.

Pay attention to both the scope of the contractual definitions in project agreements and to the scope of the work done by the environmental consultant brought in to gauge risk. To be clear, a consultant conducting a phase I assessment is arguably not obligated to address known PFAS contamination under the applicable ASTM standards because the substances are currently not considered "hazardous substances" under federal law such that a recognized environmental condition has to be noted.

Proposals are under active consideration in both Congress and within the Environmental Protection Agency to regulate PFAS at the federal level.

In addition to possible regulation under the Safe Drinking Water Act, there is mounting effort to designate certain of the most common PFAS as hazardous under federal law. Such a designation could trigger liability for owners, operators and other responsible / continued page 36

ENVIRONMENTAL UPDATE

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parties for remediation of not only future releases, but also of decades-old releases. The designation could also allow regulators and co-liable parties to recoup their remediation costs from other legally responsible parties and for trustees to seek recovery for damages to natural resources.

Though likely to change, federal regulation so far has been limited to additional tracking of PFAS use, action plans, reports and health advisories to address concerns over PFAS contamination in drinking water. EPA currently has no cleanup standards for PFAS, but has issued only an unenforceable drinking water health advisory covering a few of the most common PFAS.

In recent years and with increasing frequency, states have stepped in to regulate rather than wait for federal action. Whatever EPA does at a national level, an increasing number of states have already entered the regulatory field. More states are considering action.

For example, New Jersey regulators recently set health-based groundwater cleanup standards for PFAS at much stricter levels than those currently being considered by EPA. The state proposed groundwater quality standards of 14 parts per trillion for PFOA and 13 parts per trillion for PFOS, significantly lower than the EPA unenforceable drinking water health advisory of 70 parts per trillion.

Regulation of various types of PFAS has already been adopted or is being considered in dozens of states, including Massachusetts, New Jersey, New York, Vermont, New Mexico, Michigan, California, Washington, North Carolina and Pennsylvania.

While some such regulation may be subject to challenge based on the underlying science, the momentum of regulation is clear and developers and those involved in project development should be aware of potential future exposures to liability and take appropriate steps.

*— contributed by Andrew Skroback in New York*