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PROJECT FINANCE

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US to Review More Inbound Investments

by Amanda Rosenberg, in Los Angeles

Congress passed legislation in early August that will subject more in-bound US investments to review by CFIUS. The President is expected to sign the law.

CFIUS stands for the Committee on Foreign Investment in the United States, an interagency committee of 16 federal agencies, headed by the Treasury Department, that reviews foreign acquisitions of US companies and property for national security implications.

Previously, CFIUS only had authority to review deals in which a foreign person gained control over a US trade or business.

The new law gives it authority to review transactions where a foreign person takes a minority interest in a US company that owns or deals with critical infrastructure or critical technologies.

Minority Interests

Critical infrastructure means systems or assets "so vital to the United States that the incapacity or destruction of such systems or assets would have a debilitating impact on national security."

An example might be a section of the US utility grid.

The definition seems to set a high bar. However, in practice, any / *continued page 2*

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TAX BASIS ISSUES remain largely unresolved after a US appeals court decision in late July in a closely-watched case involving Alta Wind.

The case is headed back to the US Court of Federal Claims to be reheard and will be assigned to a new judge.

It has the potential to affirm or upset current practice in the tax equity market of assigning most of the value paid for renewable energy projects to the generating equipment as opposed to intangibles like a power contract or going concern value. Going concern value is the extra value for which a buyer might pay for an existing business due to the seller having already pulled all of the pieces / *continued page 3*

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significant energy asset could be critical infrastructure. The aggregate significance of project portfolios is also considered.

A critical technology is one that has defense applications. Examples are technologies that are subject to US export controls.

To come under the new review authority, the minority interest being acquired must give the foreign person access to technical information of the US business that is material and not available to the public, membership or observer rights on the board of directors, including the right to nominate directors, or the authority to make substantive decisions about critical technologies or critical infrastructure. The mere voting of shares is not considered the right to make decisions for the business.

Indirect investments in critical technology or critical infrastructure companies through an investment fund as a limited partner that gives the foreign person membership on an advisory committee will not be subject to review if certain things are true. The fund must be managed exclusively by a general or managing partner that is not a foreign person. Neither the foreign person nor the advisory committee may have the ability to approve, disapprove or control investment decisions of the fund or decisions made by the general partner. The foreign person cannot unilaterally dismiss, prevent the dismissal of, select or determine the compensation of the general partner. The foreign person cannot have access to technical information of the US business that is material and not available to the public due to its participation on the advisory committee.

Sites

CFIUS will also have authority in the future to review any purchase or lease of land near sensitive sites, including airports, seaports and sensitive government or military locations, if the site access could allow the foreign person to collect intelligence on activities at the site or otherwise expose national security activities at the site to foreign surveillance.

The law has no bright lines on what is considered too close to a sensitive location. CFIUS will have to fill in detail in regulations. Congress asked CFIUS to focus in the regulations on the "distance or distances" within which the site access could pose a national security risk.

Congress directed CFIUS to focus on whether certain categories of foreign persons should not be caught in the wider net that it is casting over the types of transactions that will be subject to review. The criteria must take into account how a foreign person is connected to a foreign country or government and whether the connection could affect US national security. This is as close as the final law gets to allowing a "white list" of persons not subject to the latest expansion in review authority.

Declarations

The new rules also attempt to streamline the filing process. Parties will have the option of submitting an abbreviated "declaration" that is limited to five pages. This applies to all filings, and not just filings in the new types of transactions being subjected to review. CFIUS will be able to approve the deal, request that the parties file a full notice or initiate a unilateral review. It will have 30 days to take an action on the declaration.

Declarations will be mandatory in some instances.

A declaration is required for an acquisition of a "substantial interest" in a US critical infrastructure or critical technology company by a foreign person in which a foreign government has a "substantial interest." Thus, for example, a declaration would have to be filed if a European utility that is 51% government owned were to purchase a 40% interest in a US nuclear power plant or transmission grid.

CFIUS will be able to block some future US inbound acquisitions in which a foreigner is buying only a minority interest.

Congress left it to CFIUS to decide in regulations what type of ownership or percentage interest by a foreign government should be treated as "substantial." In developing the regulations, CFIUS is supposed to consider how and the extent to which the foreign government influences the actions of the foreign buyer, including through board membership, shareholder rights and ownership interests.

A less than a 10% voting interest will not be considered substantial.

CFIUS can waive the mandatory declaration requirement if investments by the foreign buyer are not directed by a foreign government and the foreign buyer has a history of cooperation with CFIUS.

CFIUS may make the filing of declarations mandatory for other types of investments.

18-Month Delay

The wider net and mandatory filings described in this article will not become effective immediately. They will become effective 18 months after President Trump signs the bill or, if earlier, 30 days after CFIUS publishes implementing regulations.

Other changes in the legislation are effective immediately.

CFIUS will have more time to review transactions. The initial review period will be 45 days rather than the current 30 days. In "extraordinary circumstances," CFIUS can request an additional 15 days be added to the 45-day investigation that follows the review.

CFIUS will move into an investigation phase if there are unresolved national security issues at the end of the initial review period. Investigations generally will be mandatory for transactions in which a foreign government controls the foreign buyer. The overall effect is to lengthen the maximum potential review period from 90 days to 120 days. This does not include the time it takes to prepare the filing and any pre-filing CFIUS review.

CFIUS has a current backlog. Reviews today are taking four to five months, even in cases where the transaction does not move into an investigation phase.

CFIUS also will have the ability to suspend a transaction in the future while it is under review if CFIUS believes it poses a national security risk, meaning that the deal could not close until CFIUS completes its review.

The parties will be able to stipulate that the deal is a covered transaction that CFIUS has authority to review or a foreign government-controlled transaction. The effect of the stipulation is to focus CFIUS on the national / continued page 4

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together.

The typical appraisal in the renewable energy market allocates 95% to 98% of the price paid for a wind or solar project to the generating equipment. Investment tax credits and depreciation are calculated on the generating equipment and not on land, transmission assets or power contracts, interconnection agreements or other intangibles.

The case, called *Alta Wind v. United States*, involves six wind farms in California. Five of the wind farms were financed in sale-leasebacks. One was sold to EverPower. All of the projects had long-term power contracts to sell their electricity to Southern California Edison.

The owners of the projects — mostly tax equity investors — applied for Treasury cash grants based on what they paid for the projects rather than what the developer, Terra-Gen, spent to build them. The sale-leasebacks occurred in 2010 and 2011. One project was sold to EverPower in 2012.

At the time, the US Treasury was paying owners of new renewable energy projects 30% of their tax bases in the generating equipment under a so-called section 1603 program that was part of a group of economic stimulus measures that Congress passed in early 2009 to help pull the economy out of a tailspin. Anyone receiving a Treasury cash grant had to forego tax credits, but could still depreciate the project.

The Alta investors assigned 93.1% to 96.9% of what they paid for the projects to the generating equipment and the rest to other assets. Edward Settle, the public face of the Treasury cash grant review team at the National Renewable Energy Laboratory, testified at trial that NREL had a rule of thumb that 95% of the cost of the average wind farm is basis in eligible equipment.

The Alta owners had unusually strong evidence to support the overall prices they paid for the projects. Terra-Gen, the developer, had put the projects out / continued page 5

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security implications of the deal and not require it to spend time on whether CFIUS has the right to review the deal.

The new rules give CFIUS the authority to collect filing fees for processing submissions. It is unclear whether the fees will have to be paid when filing a five-page declaration or just a longer filing. Fees may be collected for all filings in the future and not just those involving sites near sensitive government facilities and critical infrastructure or technology companies and projects. The fees cannot exceed 1% of the transaction value or, if less, $300,000. The $300,000 will be adjusted for inflation.

For more information on CFIUS, listen to an episode of our podcast called "CFIUS: A Closer Look" at www.chadbournecurrents.com

New Trends

Chadbourne, now part of Norton Rose Fulbright, has hosted an annual energy and finance conference each year since the mid-1980s. The conference is attended by top executives at project developers, banks, private equity funds and tax equity shops. The 29th annual conference was at Lake George in New York in June.

The second session this year was a wide-ranging discussion about new trends in the market with the investment banker or banker equivalent of a panel of journalists on the Sunday morning talk shows. The following is an edited transcript.

The panelists are Ted Brandt, CEO of Marathon Capital, Ralph Cho, co-head of power and infrastructure in North America for Investec, Jonathan Kim, managing director and head of infrastructure finance for Natixis, Jim King, managing director and head of project finance and infrastructure for CIBC Capital Markets, and John Plaster, managing director and head of alternative energy at Barclays. The moderator is Ben Koenigsberg with Norton Rose Fulbright in New York.

MR. KOENIGSBERG: Jim King, what are the biggest risks currently in the market?

MR. KING: The two biggest risks developers face today in contracted renewables projects are transmission and rising interest rates.

Of those two, transmission is probably the one about which we worry the most while our clients appear to be more worried lately about interest rate risk. A lot of them are buying interest rate hedges to cover the period between signing the power purchase agreement and starting construction.

In other parts of our business, like infrastructure, that risk is less of a concern because it effectively gets passed through in a lot of those contracts.

There are various ways to hedge. Straight interest-rate hedges are sometimes backstopped by a balance sheet. In other cases, we are doing deal-contingent hedges where banks take risk on a non-recourse basis that projects will come to fruition.

(For more information about deal-contingent hedges, see "Deal-Contingent Hedges" in the October 2017 *NewsWire*.)

MR. CHO: In our bank deals where the interest rate floats, we require at least a minimum of 75% of the interest payments to be hedged through the maturity of the loan. Some of our clients, especially in the residential rooftop solar sector, are locking in all 100%, and they do not necessarily stop at maturity. They hedge through the full amortization of the loan, meaning the hedge also covers the expected refinancing period. Their customer revenue streams are locked in for 20 years.

If interest rates are higher than where you started, the hedge will be in the money when the debt is refinanced, which is not a bad position. Some developers have been getting paid out on these swaps. They seem like a good idea today given the upward trend in rates.

MR. KOENIGSBERG: I had lunch with a developer a couple weeks ago who said many developers focus on getting a power purchase agreement in place without focusing on the risk that the deal may become uneconomic if borrowing costs go up by 200 basis points by the time the project is built, so this is a critical thing to think about in the current rate environment.

Let's move to another topic. Ted Brandt and John Plaster, there has been a lot of interest in buying projects this year. What are you seeing in the M&A market?

M&A

MR. BRANDT: We are seeing an influx that is probably stronger than any year since 2006 or 2007 of satchels full of euros by European companies wanting to get established in the United States. That has been a huge, huge driver. These are big, well-capitalized companies that see the United States as a higher growth market with a better interest rate environment than they have at home.

The other trend is developers are selling down to passive institutional investors, like pension funds and sovereign wealth funds, and this is bringing more permanent, less expensive capital into the market. It allows the more expensive capital to rotate back out. It has been a really positive trend.

MR. PLASTER: I agree with Ted. Another interesting and positive new trend for the sector is a rise in environmental social governance or socially conscious investing that is driving more money into renewable energy.

We have been hearing lately from large investment funds that have not invested in renewable energy, but who are hearing from their limited partners that this is an area of interest, and they want to know how to get involved.

In terms of deal flow, it is helpful to the think of the market as arrayed along a spectrum, starting with asset-only deals. The middle column is partnership deals, and then there are full-platform sale deals. Asset-only is relatively straightforward. A number of investors want to partner in some form.

We have been busy on full-platform sales. Two that we worked on recently were the sale of sPower to AES and Aimco and the sale of EverPower.

AES and Aimco wanted to buy the whole company, and they bought it 50-50. They are very excited about deploying capital and developing more assets. I think it has been a very successful deal for them.

On EverPower, we had two different buyers, and, in fact, Ted and I worked on it together. He represented Innogy, which bought the development platform and Blackrock bought the assets. I think for any full platform deal it is important to consider the possibility of selling separate pieces.

Finally, there has been a huge amount of activity in the yield co space. The sponsor positions have changed hands. That could be good over time for the development community.

MR. KOENIGSBERG: Europeans and Asians have been coming into the US market. What have been their main concerns once they get here?

MR. BRANDT: Talking to the Germans about US tax reform at the end of last year was a riot. Their response was, "You live in a very crazy country."

Many Europeans believe that we are going through a period of temporary insanity and that, in the long run, we will figure out that the earth is warming.

They are not used to the complex subsidy regimes that we have or tax equity, but at the end of the day, they believe that onshore and offshore wind, solar and battery storage are the future. Some of them also believe very much in gas.

They take a long-run perspective and / *continued page 6*

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for sale in an auction. The prices paid by the tax equity investors were at most 2% above the bids received in the auction.

The government did not challenge the overall prices, but said that roughly 29% of what was paid should have been treated as purchase price for intangibles.

Its view was that the tax equity investors should have added up the value of the equipment first and then treated any remaining purchase price as basis in intangibles like customer goodwill or going concern value.

This is the approach that section 1060 of the US tax code requires when buying a business as opposed to a piece of equipment. IRS regulations require separating the assets that come with the business into seven asset classes from easiest to hardest to value. Classes I through IV are, in order, cash, things like commodities that are actively traded so that quotes are readily available, accounts receivable and inventory held out for sale. All other tangible assets go into class V. Class VI is intangible assets like power contracts, site leases and licenses. Any remaining purchase price goes into class VII and is considered a payment for customer goodwill or going concern value.

The claims court said this approach only applies to the sale of the kind of business that has customer goodwill. There is no customer goodwill in a power plant that is not yet operating and that has only a single utility as a customer under a long-term power purchase agreement, the court said.

It said the projects were worth more than they cost to build, but it called the appreciation "turn-key value" that goes into basis in the power plant, reflecting the fact that a power plant is worth more at the end of construction than the bare cost to build it.

The appeals court suggested that the section 1060 method of allocating purchase price should be used in all sales of projects. IRS regulations suggest it / *continued page 7*

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look at the rest of it as just noise.

MR. PLASTER: It is hard for international parties to understand the subsidies in the US market through the tax code. Another challenge is the amount of regulation in our market. There are federal rules, and then each state also has rules. If you are not an expert in the US power market, it can be really daunting. Once you start digging in, you realize how little you actually know.

We see a lot of interest coming out of Asia now into the US renewable market, both from Japan and Korea. The motivations are strategic and financial. It is just starting. We are going to see more investment from some Asian strategics in the US market.

MR. KOENIGSBERG: Is most of the investment in projects at the start or end of construction? Has the market moved up the risk curve?

Developers are hedging interest rate risk between signing the PPA and starting construction.

MR. BRANDT: There is liquidity at all stages. You could sell the development rights to a good project with transmission rights that does not have a power contract. There is a market for that. There is a market for projects that are just starting construction. There is a market for operating projects. The discount rates are generally lower for the latter couple of categories than the former.

It usually starts with a potential buyer asking what capabilities the developer has. Does it have the resources to see the project through to completion? Does it have the wind turbines? What is the strategy around solar equipment, given the tariffs on such equipment? Still, there is massive liquidity.

MR. KING: Not too long ago, a developer could earn a premium by waiting to sell until a project reached commercial operation. You see people selling at the start of construction today because developers do not see much, if any, uplift by keeping the project until commercial operation.

PJM Capacity Auction

MR. KOENIGSBERG: Next topic. Ralph Cho, people were pretty surprised by the prices that came out of the latest capacity auction in PJM. They were up 83% this year. Last year, prices fell 25%. To what do you attribute the swing, and what will be the impact?

MR. CHO: The prices were a lot higher than most of the lending universe expected. Bankers are definitely feeling pretty good. I see three themes emerging.

Number one is that low energy prices are affecting bid strategy. The bidders are all acting rationally.

Number two is we did not see a lot of new builds last year, and that clearly showed up in the numbers. I read that only one new-build bid into and cleared the PJM market. I think that was Hilltop.

The third thing for me is there is a continuing string of coal plant retirements, the biggest one recently being First Energy, and that has to have been factored in.

The prices had to be bittersweet from the standpoint of power plant owners. If the prices had been 80 to 100, they would have felt pretty good. But at 140, you can expect a lot of new competition to crowd into the market. There are a lot of projects that had stalled or were put on hold that may be ramping up again.

As for lenders, the high capacity price means that borrowers are likely to want to reprice or restructure existing deals.

MR. KOENIGSBERG: These are results for one year. For a rush to restructure, don't you have to believe this is a trend?

MR. CHO: No, I get that. It is one data point. But there is so much equity capital on the sidelines right now, and this is a positive development. It will give investors a reason to put money to work.

MR. KIM: If you look over a longer time period, we had one bad year the year before and one good year now. If you are going to put money to work in a five- to seven-year financing, you have to consider whether the average price supports the thesis that these projects are financeable. It does. You might have a bump in the road or you might have some smooth riding for a while, but in the end, it comes down to averaging and taking a long-term view.

MR. CHO: We were flat lining $75 to $76 out into the future, so this certainly creates some uplift on some of our deals.

Offshore Wind

MR. KOENIGSBERG: Let's move to offshore wind, given that we have Jonathan Kim, who has been active in Europe with Natixis. There were two very significant announcements that were made on May 23, where Massachusetts announced an 800-megawatt award to Vineyard Wind, which is a joint venture between Copenhagen Infrastructure Partners and Avangrid, and then there was a 400-megawatt award in Rhode Island to Deepwater.

Jonathan, is it your sense that this is the start of what will be a really big industry in the United States?

MR. KIM: I think it will have a ripple effect on the broader market. For example, we were in the market for a New England peaker, which is going to close next week, and we took a positive view on that peaker because of what is happening with offshore wind. If you are old enough to remember, peakers used to be needed to fill in during weather-related events, but now they are used for filling in around intermittent renewable energy.

Offshore is happening. PPAs are being awarded. We are positioning ourselves to take advantage of it, but we are also looking out more broadly at the effect that it will have on different asset classes in different locations.

MR. CHO: We have not seen much offshore wind here in North America, but in Europe offshore wind financings are hot. A lot of the banks that play here also play in Europe. The sector is so active in Europe that offshore wind deals reprice and refinance during construction. The pricing has fallen as low as LIBOR plus 160 basis points.

MR. KIM: There are certain things about the US that are unique, like . . . .

MR. BRANDT: . . . the Jones Act.

MR. KIM: Yes, the Jones Act. We still have to have tax equity, which does not exist in Europe. There are more strenuous protests here about offshore wind. So there are challenges here that are quite extensive.

Then you have the classic problem of the supply chain. Europe has a full supply chain to serve the offshore market. It does not exist yet in the US. Offshore commands a premium in the US. Lenders and investors are "risk on" for almost any spread at this point.

MR. KOENIGSBERG: Talk about the supply chain, because you just alluded to it with the Jones Act. You cannot use European ships here for installing turbines unless / continued page 8

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should be used when the sales price exceeds the cost to construct or any intangibles are included with the project.

The claims court had suggested that a power contract that requires electricity to be supplied from a particular power plant has no value independently of the power plant. The appeals court did not address this, but rather focused on whether part of the purchase price paid for a project not yet in operation and with a long-term power contract could be for customer goodwill. "[W]e think goodwill can arise based on contracts," the court said.

In the final analysis, the appeals court said, "the government agrees that turn-key value accounts for some portion of the purchase price." But it suggested there was also value "from having secured a customer contract, regulatory approvals, transmission rights, and various other arrangements that ensured the immediate operation of the Alta windfarms." It sent the case back to the claims court to revisit how much of the purchase price to treat as turn-key value. It also suggested the claims court consider whether the right to a Treasury cash grant and Terra-Gen indemnity if the grant fell short were also intangibles that should be backed out of the grant basis.

At the end of the day, the appeals court did not like the process the claims court used, but did not give it much guidance for how to redo the numbers. Appraisers who are not already doing so will have to consider whether to use a section 1060 approach to allocating purchase price.

The court missed an opportunity to settle whether power contacts that are bolted to a particular power plant, and cannot be transferred without the power plant, have independent value.

Some developers had switched this year in tax equity deals from paying developer fees to selling the project company to the tax equity partnership near the end of construction as a better way to / continued page 9

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you rebuild them. Bringing ships from overseas is expensive. It is complicated to comply with the Jones Act.

MR. KIM: We will leave it to you guys to figure that one out. But, no, that is an important aspect. Deepwater finessed it, but Block Island was only five turbines. How do you do an 800-megawatt project? That will be a big challenge.

MR. BRANDT: If everything that we are hearing about a GE 12-megawatt offshore turbine is for real, it will be huge development from a cost standpoint. Most of the cost of these projects is in the towers and the installation.

The Jones Act forces you to use oil and gas techniques, much like you would in deepwater drilling.

The Europeans think that they have everything down. Time will tell who is right. There is a Hatfield-McCoy type of rivalry going on across this industry.

MR. KOENIGSBERG: How much expansion will there have to be in the offshore wind sector in the US before the consolidation starts?

MR. PLASTER: I think it will take a little more time.

MR. BRANDT: There is no shortage of capital. Deepwater is not a big investment-grade company, but it has plenty of capital. On the other hand, if somebody writes a big enough check, the private equity fund owners will sell.

MR. PLASTER: I agree. There has been a lot of consolidation in the wind sector already. Some of the larger independent developers have been acquired. We see a lot of strategics interested.

MR. BRANDT: You are talking about onshore wind?

MR. PLASTER: Yes. Some of the larger US strategics have not been enamored with the risk profile of offshore. I think they will stay on the sidelines for a while, and the companies that have done offshore wind in Europe will take the lead initially in the US. Over time, these are really large capital-intensive projects, and I think you will see some consolidation.

MR. KIM: One of the concerns I have about offshore wind is it may play out the same way LNG did. We will have massive, big dollars coming out for financing. It will have a run and, at some point, the rush will stop because there is only so much offshore resource that the developers can tap.

The challenge of offshore is so huge. The barrier to entry is much higher. The projects are much more complex. There is also political resistance in certain parts of the country to offshore wind. I do not think we will see all three US coasts, including the Gulf, lined with wind turbines.

Offshore wind will have its time and, because of that, the financings will be massive, but on the M&A side, there will be only a finite amount of supply that you can trade.

MR. BRANDT: There are only eight or 10 companies.

MR. KIM: Exactly. So how long is that going to last before people say, "We have hit the end already."

MR. PLASTER: We should see the same M&A pattern that has emerged in Europe, which is there are sell downs of these assets. A large company develops a project. Then it operates the project long enough to establish a track record. Then the project is sold to a buyer with a lower cost of capital and development capital gets recycled into another project. There will probably be an interesting M&A angle, bringing in more passive capital for stakes in existing offshore wind farms.

MR. BRANDT: The optimists believe that there will be 5,000 megawatts of offshore wind PPAs handed out. The pessimists think that maybe the number will be closer to 1,200 megawatts, which is where the market is now.

It will probably land somewhere in the middle. The M&A market usually does not heat up until people have a better feel for what the cards look like.

There are signs lender margin compression is getting close to bottom.

Cost of Capital

MR. KOENIGSBERG: Next topic. Jim King, panelists at industry conferences this year have been talking about how tight the spreads are in the debt market above LIBOR. Some construction debt is being bid at 100 basis points. Some sponsors are asking for even lower margins. How long do you see this continuing? Do you see the liquidity being soaked up in a few giant LNG and offshore wind deals?

MR. KING: All of the markets are incredibly liquid. It is not just the debt market. It is not just the bank market. Debt spreads have come in. Equity yields have come in as well.

We don't see that trend reversing any time soon. If there is any pressure, it remains downward pressure.

As for the big LNG deals taking liquidity out of the market, we have committed $500 million this year to LNG transactions, and that number will likely increase by about 50% by the time the year ends.

We do not see numbers in this range having a significant impact on liquidity. There are a lot of big transactions in the market or coming to market, not just in the LNG space, and we have not seen any sign in the bank market that there is insufficient liquidity to bank those transactions.

MR. CHO: We are still seeing margin compression this year. However, there are signs that it is getting close to the bottom . . .

MR. KIM: You can't go much lower, Ralph.

MR. CHO: Exactly. Some of the capital that we have been seeing come into the market, especially from Asia, is starting to tap out. Some of the potential investments are no longer making sense for these investors.

We have heard that the pricing on short-term construction loans is going as low as LIBOR plus 75 basis points. Fully-contracted deals are still at 125 basis points over, even on back-levered loans.

Quasi-merchant deals have now come in as well. We are seeing such deals at 275 over. We have a deal in the market at LIBOR plus 275 because the sponsor did not want to pay any more than that. My view is rates cannot go much lower.

MR. KING: This is a very active market with a lot of liquidity. You see developers doing some pretty smart things to boost their returns.

Banks are doing similar things. We would love for the pricing to move back up. I am sure the equity sponsors in the room would like for the yields to move back up as well.

MR. KIM: It is the new European and Asian investors coming into the market that is driving the spreads down. If the financings were coming solely from institutions that have US branches or US operations, then I think the spreads would be much wider.

We are seeing investors that you have not heard of before from the Middle East, from Europe, from / continued page 10

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support a fair market value basis in the power plant. After the latest Alta decision, that strategy seems no better than developer fees.

A separate test case of whether developer fees paid under a development services agreement by a project company to the developer go into basis was the subject of a four-day trial in late July in the claims court. A decision is expected later this year.

The project company in that case paid the developer a developer fee of $50 million, or 12.3% of project cost, on a wind farm in Illinois and put the amount in basis for a Treasury cash grant. The Treasury said the developer fee should not count toward the cash grant because it was circled cash: the developer made a capital contribution to the project company to pay itself a fee. The government also argues that the fee is not a real "fee" because it was a function of what the developer could have earned on a sale of the project rather than the actual services performed.

The developer fee case is *California Ridge Energy, LLC v. US*. A companion case that was heard at the same time involving a second wind farm with the same issues is called *Bishop Hill Energy LLC v. US*. (For earlier coverage, see "Treasury Cash Grant Update" in the February 2016 *NewsWire* and "PPAs and Developer Fees" in the February 2018 *NewsWire*.)

A PHYSICAL PRESENCE is no longer required for companies making sales to have to collect sales taxes, the US Supreme Court said in late June.

The internet is making it hard for brick-and-mortar stores to compete. South Dakota, which does not have an income tax and relies on sales taxes for roughly 60% of its revenue, adopted a new law in 2016 requiring out-of-state sellers to collect and remit sales taxes as if they have a physical presence in the state. The new law applies only to sellers with more than $100,000 in annual sales in the state or

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Asia, and it is because the potential returns in their own markets are so horrible that 1% sounds great.

As long as the global interest rates are relatively low or flat, I think the spreads are going to stay this way. The turning point will be an event where rates rise in Asia or Europe. Money then will be taken out of the US or the Americas and redeployed outside the US. That is when we will see the liquidity start to drop.

MR. KOENIGSBERG: So it is not just US rates, but global rates.

MR. KIM: Yes. We have to be mindful that it is global rates now. It is not just what the US Federal Reserve doing.

MR. KING: But we also know one thing that changes spreads on the debt and equity side is difficult deals. So notwithstanding that there is a lot of liquidity in the bank market, there are some deals that are struggling, including underwritten transactions. That tends to force people to take another look at how the market is behaving. It is early. Some of those deals are in the market now.

Buyers are discounting projected cash flow from utility-scale solar projects at 6.5% to 7.5%.

MR. KOENIGSBERG: Maybe some renewables deals with merchant tails is a category.

MR. PLASTER: Let's also not lose sight of how the future rate increases that the US Fed has signaled will occur this fall and into next year are starting to have a ripple effect through the currency markets. They add to exchange rate volatility and put stress on emerging markets. Some investors had moved to those markets as returns got tighter in the US.

MR. BRANDT: Inflation risk also has to be considered. We are seeing investors for the first time in 10 years start asking what their real rates of return are after subtracting projected inflation. They are worried that US inflation will increase given the massive borrowing by the US government to finance its growing deficits and given the tight labor market.

Institutional investors, like pension funds, have been moving money into this sector. It is fixed-income money — it is not equity money — and for the first time, we are hearing institutional investors ask whether the returns are high enough.

That is as bullish a sign as one can get. It is not happening in the bank markets, but we are seeing it in the equity markets.

CFIUS

MR. KOENIGSBERG: Let's turn to audience questions.

MR. HESSE: Balduin Hesse, CEO of Frontier Renewables. You mentioned acquisitions and interest in the US by new European and Asian investors. Have you seen any increase in CFIUS approval risk? We run into that as a condition precedent in some of our project asset sales, which can take 90 days, maybe even longer. Given the current administration, is there a new risk about CFIUS, whereas maybe previously it was a rubber-stamp process?

MR. PLASTER: Absolutely. We have evaluated CFIUS risk on deals for a while, but we believe the threshold has gotten higher, particularly around Chinese inbound investment. In some deals, we have seen potential buyers hire counsel and evaluate the likelihood of getting CFIUS approval before spending time and money on an M&A process.

MR. BRANDT: I would add that there are also significant delays in the CFIUS reviews. It used to be a 90-day process. Now we are hearing about extensions on almost every request, so that it is becoming a four- or five-month process even for buyers from Scandinavian and other European countries where there seems little risk of the transaction ultimately being rejected.

MR. CIRINCIONE: Guy Cirincione with Siemens Financial. Jim King, you mentioned pre-start hedges that clients are doing with you. What is the logic for that hedge? Are you hedging to what you think will be the financial close of the construction financing? Are you hedging way beyond that period? Are you picking an estimated amount of debt to hedge?

MR. KING: We are pre-hedging the expected term loan portion of those transactions, and the hedge is not very different than the hedge that would be executed at financial closing. It is just being put in place earlier. It is the expected term loan quantum, and there is an assumed start date.

If the actual start date moves, then there are mechanisms in the hedge to account for that. For example, if the closing date is delayed a month or two, then there is an incremental cost associated with that. That is generally how the structures work.

MR. MARTIN: Let me ask Ted Brandt a question. Tell us the current discount rate for winning bidders in auctions of projects.

MR. CHO: Tell us all your secrets.

MR. BRANDT: I don't think that they have changed dramatically for individual project bids and even the 80 basis points increase in the 10-year treasuries has not changed it that much. We are still seeing solar selling at 6.5% to 7.5% on an unleveraged 35-year after-tax basis, and wind is 8% to 9.5% on a 30-year unleveraged after-tax basis.

The Hunt For PPAs

Three prominent wind developers and the head of electricity procurement for a utility talked about lessons from recent utility procurements, corporate PPAs and hedges at the 29th annual global energy and finance conference in June. Corporate PPAs accounted for all the wind PPAs signed in the last quarter of 2017. They are on a pace this year to set a record. The levelized price for wind electricity was under $20 a megawatt hour in 2017. Prices are lower still in 2018.

The panelists are Laura Beane, CEO of Avangrid Renewables, Paul Gaynor, CEO of Longroad Energy Partners, Tim Kawakami, director of purchased power for Xcel Energy, and Dennis Meany, president of Lincoln Clean Energy. The moderator is Rob Eberhardt with Norton Rose Fulbright in New York.

MR. EBERHARDT: Tim Kawakami, Xcel ran a closely watched request for proposals to supply 1,800 megawatts of electricity. More than 100,000 megawatts were bid. The results were announced this week. Tell us what happened.

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more than 200 separate transactions.

The state then sued three out-of-state retailers in an effort to get a decision on whether the new law is constitutional.

The case reached the US Supreme Court as *South Dakota v. Wayfair*.

States are not allowed under the US constitution to erect barriers to interstate commerce. The US Supreme Court held in a case called *National Bellas Hess* in 1967 that a mail-order company could not be required to collect sales taxes for Illinois where it had no physical presence. It reached the same conclusion in another case in 1992 involving a mail-order business making sales in North Dakota in a case called *Quill Corp*.

In between the two decisions, the court offered a set of guidelines in another case called *Complete Auto Transit* for when states may tax interstate commerce. Interstate commerce can be required to bear its fair share of taxes, but the taxes must be tied to an activity with a substantial nexus with the state, they must be fairly apportioned and they cannot discriminate against interstate commerce. They should also be fairly related to the services the state provides.

Justice Anthony Kennedy, who is stepping down, wrote the majority decision. Kennedy said the requirement for a physical presence in the state before a company can be required to collect sales taxes "becomes further removed from economic reality" with each passing year. Forty one states, the District of Columbia and two US territories asked the court to drop the physical presence requirement. Kennedy said sparing internet sellers and mail order houses from having to collect taxes lets them undercut local businesses on prices.

The decision was 5-4.

Chief Justice John Roberts wrote a dissent joined by three liberal justices: Breyer, Sotomayor and Kagan. Roberts said that any change in whether e-commerce must collect sales tax should be made */ continued page 13*

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Xcel Numbers

MR. KAWAKAMI: I am not here to announce winners, and prices and even the losers, but we did file a couple days ago. We worked on the solicitation for the past year. It was big deal.

Keith Martin and I were talking last night about the large amount of capacity bid. It was actually 112,000, but that is a little misleading because a bid can be the same project priced 10 different ways, and a lot of bidders did that.

We had 238 projects bid, which was about 58,000 megawatts. That is also a little misleading because a project can be defined in different ways, too. Variations of the same project are driving those numbers up.

The pricing was tremendous. We liked it so much that we are taking a lot. The median prices were wind, $18 a megawatt hour, and solar $29. Obviously, we are looking at winning bids in the low teens for wind with low 20s for solar. Batteries were bid in at $7 premiums, mostly sited with solar.

We filed to take 1,100 megawatts of wind, 600 megawatts of that being PPAs and 500 megawatts where ownership will be transferred to Xcel through a build-transfer model where the developers build the projects and then sell those projects to us at commercial operation. There are 700 megawatts of solar, all PPAs.

For my friends who were on the panel yesterday discussing storage who said that utilities do not know how to integrate solar, we will take 275 megawatts of utility-scale solar. That is four projects. They vary in size from 50 to 100 megawatts. We are excited to see how the storage projects can be used in our system, especially since we do not have an ancillary market. We are modeling the value to the system and are excited to do that.

We are also taking 300 megawatts or so of electricity from thermal power plants. Those are mostly existing facilities that have or will come off contract.

MR. EBERHARDT: We have three developers. What do you conclude from the results of this RFP?

MR. GAYNOR: I didn't get a letter. [Laughter]

MR. EBERHARDT: Dennis Meany or Laura Beane, did you get a letter?

MR. MEANY: No.

MR. GAYNOR: No, we didn't bid, but I think that . . . [Laughter] . . . think about the math. If you take out the multiple bids from one project, it is still a pretty low batting percentage.

That has been our experience, not with Xcel, but with others, and certainly in the corporate world with the corporate RFPs. You have to take a lot of swings to get a hit, and that is costly: it is time consuming and frustrating for the people who did not get a letter. It is great what Xcel is doing. It is hard to be on this side of the table.

MS. BEANE: We did bid many iterations of projects, and we remain hopeful. Tim, you know what to do . . . . [Laughter] I'm joking. But really, it is a buyer's market, and it is extremely competitive. Just when you think you found the bottom, the prices keep falling. I don't know whether it is credible, but I heard the other day that a sub-$10 PPA was signed. I don't know if any of others have read about that.

MR. MARTIN: We know of $12.

MS. BEANE: One was $9.98 or something like that. There are many different players in the market. They have different business models and risk profiles. We are a long-term owner and operator. That's what we do. We want to continue to own our assets for the full duration of their useful lives, which is now extending further and further with new technology and repowering opportunities. For us, the pricing is a return question.

We are not going to make a long-term investment in something on which we cannot get a reasonable return for shareholders. It is a tough market. You really have to work hard and spend a lot of time and resources even to find out whether you are in the game.

MR. EBERHARDT: Dennis Meany, anything to add?

The winning power prices bid into the Xcel auction were in the low teens for wind and low 20s for solar.

MR. MEANY: The only thing I would add is that none of what Tim said is surprising. The pricing and the amount of demand, as the other folks have said, are functions of a very competitive market.

MS. BEANE: But on the positive side, because I am a glass half-full type of person, I think this is a great example of RFPs where utilities are decarbonizing their fleets. They are moving in that direction despite what is happening at a federal level. They have decided that renewables are inexpensive to purchase and bring lower operating costs.

I will also put in a plug for PPAs. We are seeing a trend for utilities wanting to own renewable assets. I was on the regulated side before. I know why. They have rate bases. But PPAs should be attractive as well because they shift risks away from the utilities and utility ratepayers to us, as developers and owners.

Customers essentially pay only if the wind blows or the sun shines. The utility does not have to worry about its ability to use the tax subsidies. I am encouraged that regulators seem to be taking the risk-shifting element seriously. We just saw evidence of this in the PacifiCorp RFP. It is the best solution for customers overall to have some combination of utility-owned assets and PPA projects.

BOT Projects

MR. EBERHARDT: Tim Kawakami, how has Xcel thought about PPA versus build-own-transfer, and what mix are you seeking?

MR. KAWAKAMI: We are just trying to catch up a little bit, as far as the ownership goes. Our model is basically to replace coal with renewables. We are shutting down coal plants under what we call the Colorado energy plan. The reason we have an ownership component in that plan — if it gets approved — is because we are going to take 660 megawatts of coal off line.

We retired 700 megawatts of coal in the last five years. PPAs are still good, I agree. I think the commissions like a mix of ownership and PPAs. We will have about 12,000 megawatts of wind by 2021. We will own about 5,000 megawatts of that. We do not want to own it all. We are not like other utilities that prefer to own everything.

I believe in PPAs. My job is to negotiate the PPAs, so I would be without a job without them. We like balance. I agree with Laura that the commissions also like balance.

MR. EBERHARDT: Paul Gaynor and Dennis Meany, how attractive are build-own-transfers as opposed to PPAs?

MR. GAYNOR: We are indifferent. We may end up owning some assets, but our business model is / continued page 14

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by Congress since there is the "potential to disrupt a critical segment of the US economy." Roberts said the burden to collect sales taxes is significant. More than 10,000 state and local jurisdictions impose sales taxes, each with "different tax rates, different rules governing tax-exempt goods and services, different product category definitions, and different standards for determining whether an out-of-state seller has a substantial presence," Roberts said, quoting from a 2017 Government Accountability Office report to Congress. Software to facilitate compliance is in its infancy.

Congress has been unable to reach consensus on the issues. Four Democratic Senators from Montana, Oregon and New Hampshire, which do not have sales taxes, introduced a bill in the Senate on June 28 to reinstate the physical presence test. Several other bills have been pending in the current Congress. New Hampshire Governor Chris Sununu, a Republican, vowed to protect New Hampshire-based companies from having to collect sales taxes for other states.

New Jersey promptly passed a remote sellers bill with the same standards as South Dakota. A number of other states had passed similar bills before the Supreme Court decision with plans to put them into effect after a positive decision. Lawsuits involving online sales taxes in five states are still pending in the courts.

A similar concept to physical presence comes up in a cross-border context. It is called a "permanent establishment." More than 3,000 tax treaties bar countries from taxing remote investors or sellers who lack a permanent establishment in the country. A draft European Union directive would treat digital service providers as having a "virtual" permanent establishment if sales proceeds exceed €7 million in a tax period. The US has opposed any change in this direction because of the effect on large US internet companies.

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to develop and sell, so frankly we would rather develop and sell to someone like Xcel or Berkshire Hathaway Energy or somebody like that than to have to run a process to sell. Xcel is a good buyer of assets. It has the right cost of capital and a built-in tax appetite, so that's all great.

MR. MEANY: We are long-term owners. There is a store near me in Connecticut that has two rules set in stone. Rule number one is the customer is always right. Rule number two is if the customer is wrong, see rule number one. We will respond to the market.

MS. BEANE: We are in the same position. We have been bidding both PPA and build-to-sell options because, ultimately, you do what the customers want. I could envision at some point in the future purely build to sell.

MR. EBERHARDT: Laura, your company had some exciting news a few weeks ago about the offshore wind solicitation in Massachusetts. Do you want to tell the audience about that?

MS. BEANE: You bet! Massachusetts had both an onshore and an offshore RFP. Our joint venture project, Vineyard Wind, is owned half by Avangrid Renewables and half by Copenhagen Infrastructure Partners.

We bid in and were awarded an 800-megawatt contract, and we are very, very excited about that. We were a little surprised, to be honest. A view appeared to be taking hold that the best thing to do in this market to kick start a new industry is to make awards to two different developers so that instantly you have a diversified supply chain.

We actually thought that was a good idea. That said, we are thrilled to have been awarded the full project. It will give us some advantages in terms of scale.

There is so much offshore activity in the Northeast. You have a Connecticut award that will be announced later. New York will release an RFP this fall. I think it is starting with 800 megawatts. New Jersey has made commitments to offshore. There is all of a sudden tremendous momentum in the offshore market. Ours is a very large project. The first phase is targeted to come on line in 2021. That is a very aggressive timeline.

By 2022, we will have the full 800 megawatts on line. I have become a real believer in offshore in the Northeast. The fundamentals have come together in a way that genuinely make offshore cost-competitive relative to the alternatives in those regions. You should see a significant build-out in future years.

PPA Mix

MR. EBERHARDT: Dennis Meany, do you see traditional utility PPAs being an important part of your business for the next 12 to 24 months?

MR. MEANY: Yes, because they remain a strong part of the offtake market. The traditional utility PPAs are very competitively priced because they put less risk on the developer than the corporate PPAs do.

MR. EBERHARDT: What percentage of your development pipeline do you think will be contracted with a traditional offtake arrangement as opposed to corporate or hedge alternatives?

MR. MEANY: Given the markets we are in — SPP and ERCOT — we will be seeing a lot more corporate PPAs. We did a very large 228-megawatt PPA with Amazon for a project that came on line last July.

At the moment we have a mixture of corporate PPAs and hedge contracts and no utility PPAs. We have done utility PPAs in the past.

MR. EBERHARDT: Paul Gaynor, what percentage of your pipeline will be traditional PPAs?

MR. GAYNOR: If we are moderately successful with the utility RFPs, less than 20%. Most of our offtake arrangements going forward are likely to be corporate PPAs or hedges.

MR. EBERHARDT: Laura Beane, setting aside the offshore market, do you have a different percentage?

MS. BEANE: No. We have been bidding aggressively into utility RFPs and are certainly hoping for continued success there. Last year, all but one contract that we announced were with corporate customers. We definitely see a lot of demand in that area, and I fully expect it to increase. We have not seen much aggregation yet of corporate customers, but when it comes, it will really expand the market.

There are a lot of companies that want to move to 100% renewables, but they are too small to require all the output from a single wind project.

MR. EBERHARDT: So for the 80% of the projects in the pipeline that are not going to have traditional offtake arrangements with utilities, you basically have three options: a bank hedge, a corporate PPA and a proxy revenue swap. Paul Gaynor, how do you evaluate the three options? Do you have a general preference or is it project-specific?

MR. GAYNOR: On the corporate side, it is an RFP world. With hundreds of companies bidding in, the hit rate is probably less than 10%. But you have to chase them because some of the contracts are sizeable and interesting and in places where we think we already have a project that might suit the buyer. So they will remain a pretty big part of what we do.

Hedges are like a roller coaster ride. We just closed a deal a couple weeks ago in ERCOT and you end up biting your nails all the way to the finish line waiting for bankers and tax equity guys to sign off on documents. You hope that the natural gas market will not tank in the last couple weeks before the closing.

The potential volatility feels dangerous to me. So we do not want to say our whole business model will be based on the hedge market because you are held hostage to fluctuating prices.

We have looked at proxy revenue swaps. I am on the board of RESurety. Lee Taylor is in the back of the room. It is a super interesting product, but we have not had a project yet where the benefit outweighed the cost.

MR. EBERHARDT: Dennis Meany, anything to add?

MR. MEANY: Each one of the alternatives has its own problems. Paul mentioned the hedge contract problems. There are two big issues with corporate PPAs. The credit story is often difficult, particularly when the offtaker does not want the rated entity to be the counterparty to the contract or if the offtaker is simply not investment grade.

The proxy revenue swap has issues around how the proxy part of it is calculated. We are comfortable with it. Like Paul, we spent a lot of time on the product, and we are getting close to making one work, but you have to explain to your investors why you are giving up the upside. They are also limited to 10 years, which can work, but the term affects your financing and how your tax equity is sized.

MR. EBERHARDT: Laura Beane, anything to add?

MS. BEANE: I relate so much to what both of you have said. I feel like I have two new friends that I just want to hang out with at some point. I think we have a lot in common and a lot to talk about! You can come too, Tim. [Laughter]

MR. KAWAKAMI: Look at the smile on your face. Don't tell my executives.

Risk

MS. BEANE: None of the three products is easy, and hedges and proxy revenue swaps are expensive. But hanging out in the ERCOT market on a hot day with a project that is not generating is also expensive.

There are tradeoffs. Sophisticated risk management has become an absolute necessity in our world. If you do not have a full energy management desk with */ continued page 16*

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US IMPORT TARIFFS remain a challenge.

The US started collecting a 25% tariff on July 6 on a list of Chinese goods that accounted for $34 billion in imports last year. Similar tariffs will go into effect on another $16 billion in imports on August 23. The $16 billion in additional products are mainly industrial goods — iron and steel products, machinery, motors, batteries used in some electric vehicles, voltage regulators, electronic integrated circuits, electrical meters, insulated electric conductors, locomotives and railroad equipment — but they also include solar cells and panels.

China retaliated promptly by imposing a 25% tariff on 545 US products on July 6 and announced another 114 US products on which tariffs will be collected starting in late August.

The US then upped the ante by releasing a separate 194-page list of another $200 billion in Chinese products on July 11 on which tariffs may be imposed as early as the fall. The US Trade Representative has scheduled four days of hearings from August 20 to 23 to hear from industry representatives who want to strike items from the $200 billion list. The experience to date suggests items are hard to remove. The smaller $16 billion list originally had 284 articles on it. After hearings, the US Trade Representative removed five.

The $200 billion list includes 28 pages of foodstuffs, 39 pages of minerals and chemicals, plus iron, steel, copper, nickel, lead and zinc products, cobalt, cadmium, steam turbine parts, various kinds of batteries and solar inverters. The original Trump plan was to collect a 10% tariff on the $200 billion list, but he raised the amount to 25% on August 1.

China retaliated on August 3 by announcing it will impose tariffs at varying rates of 5%, 10%, 20% and 25% on another 5,207 US products that account for about $60 billion in US sales. No date was set. It said the date depends on US actions.

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people dedicated and living and breathing those markets every single day and you do not have a wide portfolio of options and tools in your tool belt to help manage that risk, it will be tough to play.

Most new offtake arrangements in the US market are corporate PPAs.

The market is becoming increasingly risky for developers with corporate PPAs because you wear the basis risk. You wear the risk of the project. You either need very sophisticated people and tools in order to manage that effectively or to have a really high risk tolerance. There is a lot of risk involved.

MR. MEANY: Laura is spot on. It has become a much more complicated business than it was 10 years ago. Every new RFP for a corporate PPA seems to involve a new idea for how to push risk back on the developer.

MR. GAYNOR: I am excited to see how the market changes when the tax credits expire. It will be interesting to see what kind of revenue contracts will be financeable and doable from an economic point of view, what kind of risk tolerance project investors and bankers will have for a five- or seven-year PPA.

I think that is where this market is headed. It is moving to a sub-10-year revenue world. That could probably work without the constraints that the tax equity investors have been putting on projects.

MR. EBERHARDT: That is how the combined-cycle market works, so there is no reason to think once you take away the tax credits that you will still need 10- and 12-year PPAs.

MR. MEANY: That world carries a lot more risk associated with the back-end electricity price. Right now, we have to worry about what electricity prices will be outside the hedge term after year 12, but once the production tax credits expire, we may have to worry about what it will be after five, six or seven years.

MS. BEANE: I echo that. The shorter the duration today, often the more attractive the project looks because you are banking on a back-end curve that historically has looked attractive when, in reality, we have seen it fail to deliver. What happens after the contract period for projects with thin margins where the hoped-for prices do not materialize? That is an interesting question.

MR. KAWAKAMI: We have been trying to help with that. We could be the aggregator that you described by aggregating customers who are interested in renewables.

We have pilot programs in a couple states where we are trying to do that. There is a lot of demand, but our regulators have not really embraced it yet. Any time you see a regulatory filing like that, try to support it. It would be good for the industry. It would be good for the developers, too.

We can manage the basis risk that you would otherwise have if you dealt with corporate offtakers directly. By doing it through the utility, the basis risk is on us. By doing that, we minimize the cost of electricity and socialize the risk to our ratepayers because they benefit, too.

MS. BEANE: I like that idea.

MR. KAWAKAMI: Can I be your friend now? [Laughter]

MS. BEANE: You can come and have drinks with us now, too. [Laughter]

Hedge Availability

MR. EBERHARDT: Let's talk about a few things that are going on in organized markets. Are hedges viable in ERCOT and SPP today for long-term deals? Are the tenors and prices being offered workable?

MR. GAYNOR: There is a whole fear versus greed thing. Developers like us have went out and locked in PTC-qualified turbines, and now there is a race against the clock to find a place to put them. Where are we going to get a permit to build? Where are we going to get an interconnection agreement signed? Where will we have a PPA?

Everybody is pointing their guns at ERCOT or SPP because projects can be built more quickly there. Frankly, that is what has happened to us and why we are concentrating all of our wind efforts in ERCOT.

The question is what is available there. We just did a 15-year hedge on a project called Rio Bravo. We closed it a couple of weeks ago. It was a P99 hedge, and Citibank was the offtaker. Citi had some appetite to go a little longer than the conventional hedge. We hope the market likes that part of it.

The project is in a part of Texas that has a great curtailment and congestion story. It is in south Texas, so the wind is not as strong, but you do not have the congestion and curtailment baggage of the panhandle or west Texas.

We think there are spots that still make sense. However, pricing is continuing to soften. It is that nail-biting thing I talked about earlier. Prices have come down 25¢ to 50¢ in the last month or so. It gets close to the margin where deals are go-no-go.

MR. MEANY: I agree with that. Hedge prices were over $26 or $27 two years ago. Gas prices have fallen since then, and hedge prices are below $20 today or maybe better than that in the south. Hedges at those prices generally still work, which is good news and bad news.

It is good news because they work because turbine prices have fallen enough to make them work. The bad news is that so many projects can still be built, so you have a lot of wind and now solar being built in ERCOT, and that creates congestion issues and puts further downward pressure on prices.

MS. BEANE: My view is you have to look at individual projects to tell whether the current pricing works. A lot of projects are being built, so clearly it works for some projects.

MR. EBERHARDT: So today there are hedges available for the right project. You can do a hedge in ERCOT and SPP.

MR. MEANY: The hedge providers really like the product. They offer to do tax equity if we will take their hedge. Pricing is an issue, but hedges are generally available.

MR. GAYNOR: I don't think there is an inexhaustible supply of hedge counterparties for the number of wind projects that are trying to get done. Not every wind project will be able to attract the attention of a hedge provider.

MR. MEANY: SPP is very different from ERCOT. SPP South is a much less liquid market than ERCOT. Hedges are done, but there are not many counterparties to do them. In SPP North, hedges are probably not available at any length, and certainly not for terms of 10 years.

MR. EBERHARDT: A hot summer is expected in ERCOT. Reserve margins there are tight. Electricity prices are expected to spike in some hours at as high as $9,000 a / *continued page 18*

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A 25% tariff would apply to US LNG exports. The action could jeopardize a planned $43 billion Alaska LNG pipeline that had hoped to supply about 75% of its LNG to China. The project was already facing an additional $500 million in construction costs due to US import tariffs on steel. China was the number three customer last year for US LNG exports, according to the US Energy Information Administration. It bought 15% of US exports.

Trump threatened in separate interviews in July first to subject another $200 billion in Chinese products to tariffs and then later to impose tariffs on all $505 billion in Chinese imports unless the Chinese stop retaliating with their own tariffs.

At some point soon, what is on the target lists will cease to matter if close to all Chinese products are covered.

The Chinese renminbi has dropped 9% in value since April against the US dollar negating some of the effects of the US tariffs, but also making it harder for US goods to find a market in China. The dollar has been strengthening against all currencies. Economic theory suggests that tariffs eventually make US trading partners less able to afford US goods and services.

Meanwhile, the Canadian government is challenging in the US Court of International Trade a 30% tariff that the United States started collecting on imported solar panels and cells last February on grounds that it violates US obligations to Canada under the North American Free Trade Agreement. A similar suit by three Canadian solar manufacturers failed after a US appeals court indicated, while turning down a request for an injunction, that the three manufacturers were unlikely to prevail on the merits.

Six countries have filed complaints with the World Trade Organization about tariffs the United States is collecting on imported steel and aluminum. The six / *continued page 19*

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megawatt hour. What are developers with projects doing? How do they view the $9,000 an hour? Is that a good thing or is that a bad thing? [Laughter]

MS. BEANE: It depends. We saw prices over $4,000 just the other day, so the fear is real. Whether or not the market is a little overheated now remains to be seen.

It will be interesting to see whether ERCOT gets through the summer unscathed. There is a lot of fear today. If you have merchant capacity to sell, the high prices are a wonderful thing. If you have a hedge, it is probably really depressing because you are giving up a lot.

Wind developers with stockpiled equipment are increasingly focused on Texas where projects can be built quickly.

MR. MEANY: With the hedge, the fear is that the price hits $9,000 at a time when there is no wind. Prices spiked at the beginning of February. They spiked again a few weeks ago, but in the past week, the forward curves are off $40 for August.

It is true there have been some high intervals, but I think the market may be calming down. The volatility is mostly a 2018 and even a 2019 problem. Prices in the forward market for 2021 and 2022 have not moved much.

Corporate PPAs

MR. EBERHARDT: Another trend in the corporate PPA space is that some of the major corporate buyers are balking at the idea of as-generated volumes. They are looking for firm volumes. Microsoft, in particular, is being pretty vocal about this. It says the as-generated PPAs that have been signed over the past five years have not been a great deal for corporate offtakers.

Are any of you involved in those discussions? Are you seeing corporates pushing you for firm output or to pay for firming services behind the scenes?

MR. MEANY: The corporates have an accounting issue. If they fix the quantity and fix the shape, then all of a sudden they are in the world of hedge accounting, and they do not want to be there. That is good news for us because they have to take an as-generated PPA. However, many of them are trying to figure out how to take a shaped product while getting the accounting treatment they want.

Lee Taylor with RESurety, who is in the back of the room, has been working on bolt-on products that remove some of the shape risk from the corporates. It gets very complicated. You have multiple hedges.

MR. GAYNOR: That goes to the point that was made earlier about the level of complexity now in this market. It has become rocket science in many ways for sophisticated buyers like Microsoft, Amazon or Google to procure electricity. These guys finally understand what they have bought. They do not want to do it again, and they are saying, “You go fix the problem. You bring me a solution.”

Perhaps you do it with a trading desk or some other exotic solution to try to insulate them from shape risk. If you can make a complex problem easy and present a simple package to someone like Microsoft, I think you will find an eager customer. It is incumbent on people like us to try to find solutions.

MS. BEANE: I agree. Another thing that we have seen is an appetite for directly delivered. A couple of the big corporate customers are not just committing to 100% matching of renewable energy credits with their demand, but they are also saying, “We do not want any brown power anywhere.” It is a new challenge on which we are working with our balancing authority in the Pacific Northwest to meet their load directly and be able to show them that what we are delivering is wind or hydro or something else that is carbon free.

I think there is more to come on this. They are very sophisticated business people. They were not in the power world until recently, and they are becoming sophisticated buyers very quickly and demanding solutions to difficult problems.

Merchant Solar?

MR. EBERHARDT: There have been corporate PPAs signed for solar, but I think the bulk have been for wind projects. The overwhelming majority of hedged deals have been wind deals.

Paul Gaynor, your company is working on a hedged solar deal in ERCOT. Are we about to see a flood of merchant solar projects?

MR. GAYNOR: Not yet. It still feels like wind is leading the charge. About 90% of the corporate activity that we have seen is solar. Most such contracts are arranged by brokers.

Outside of ERCOT, in places like Virginia and Utah, most new offtake contracts are corporate PPAs.

MR. EBERHARDT: Laura Beane, are we about to see a string of merchant solar projects?

MS. BEANE: We have not been exploring hedges for solar projects, but I do not rule them out. If hedges become widely available, then a market will develop around them.

MR. EBERHARDT: Dennis Meany, is Lincoln Clean Energy doing any solar?

MR: MEANY: Yes, and it is a difficult product for us given how it is being priced. It will vary by market. There are places that are not terribly windy where solar is the competitive alternative.

In ERCOT for the last three or four years, the solar hedge price has been just $2 too low. Solar costs are falling, but so are solar hedge prices. Paul, you are closer to this, but my impression is some solar projects are moving within striking distance of being in the money for hedge contracts.

MR. GAYNOR: We signed a solar hedge in ERCOT. We are trying to get the deal closed. The hedge is definitely in the money. It is almost as competitive as wind. I would have not said that 10 years ago.

MR. EBERHARDT: Another trend lately has been the need to aggregate multiple offtake arrangements in a single project. There might be three or four different offtakers. Are you seeing 350- and 400-megawatt projects that have to have more than one offtaker to work?

MS. BEANE: We are not working on any. That said, we have a California asset right now that is 12 years old that has six offtakers. So we have done it before, but I would not want to do it again because you are managing separate PPAs with all those different customers off of a single asset and it gets really complicated, especially if you need to do anything with the asset and then have to get consent from so many different parties. It is not a very manageable structure.

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are the European Union, Canada, China, Mexico, India and Norway. The US position is that the WTO has no say over the US actions because the tariffs were imposed on national security grounds. At the same time, the US has asked the WTO to declare illegal retaliatory tariffs that most of the same countries imposed on $23.4 billion in US goods in response to the US tariffs.

Separately, the Senate passed a bill that waives US tariffs on around 1,800 raw materials and intermediate goods that US manufacturers use to make other products. The measure will require another vote in the House in September after the Senate amended the House bill. This miscellaneous tariffs bill has been in the works since 2016 before Trump took office. Congress directed manufacturers who want exemptions to petition the US International Trade Commission. The commission whittled 2,500 requests down to a list of around 1,800.

Both the House and Senate have rules against consideration of earmarks for individual companies. The measure was considered under a suspension calendar under which Congress suspends its rules.

CARBON TAXES remain in the spotlight, although only dimly so.

No action is expected in the near term. However, growing budget deficits may leave the US government with few other good options to fund the government in the long run.

US House of Representatives passed a sense of Congress resolution on July 19 that any tax on carbon emissions would be bad for the US economy and families. The vote was 229-180.

Rep. Carlos Curbelo (R-Florida) introduced a 71-page bill four days later that would impose carbon taxes in three places. The bill is H.R. 6463.

First, a tax would be imposed on fossil

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PPAs

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MR. GAYNOR: We see this in solar. We have a 100-megawatt project. We bid into an RFP and got selected for 50 megawatts, so we have 50 under contract and 50 not sold. You hire a broker to try to find more. The broker is providing an aggregation service, so to speak. That is the only thing we have seen.

Audience Questions

MR. EBERHARDT: Let's see whether there are any audience questions.

MR. SAXENA: Himanshu Saxena, CEO of Starwood Energy Group. Great panel, guys. This question is for Tim Kawakami. We saw very low electricity prices a few years ago in California where the PPA pricing was at a point where investors like us were looking at the numbers and concluding the projects no longer make sense. So somebody is doing it for volume, and not for profitability. As a buyer of energy, do you worry that some of these projects with really low-priced PPAs are not going to be able to get built because deals at those electricity prices are out of the money?

MR. KAWAKAMI: We do, particularly now at these prices. What we have tried to do to mitigate is tighten our security requirements, like on pre-construction security. Developers who have not dealt with us before say, "You are so far out of the market with your security requirements," but they are our protection against wasting time on projects that are not going anywhere. We make developers post security earlier in the process and give them a strong incentive to get the job completed.

Once the project reaches commercial operation, we will lower the security. Until then, we want them to perform.

MS. IGLESIAS: Silvia Iglesias, NextEra. No one mentioned PPAs with the US government. Would any of you care to comment on those and their financeability?

MR. GAYNOR: When we were called First Wind, we were an approved vendor on both the wind and solar side to the US government, but it turned into nothing. The procurement rules and processes are super cumbersome, often multiyear kinds of processes. I don't have that time in my life. I don't.

MS. ALLEHAUT: Benoit Allehaut with Capital Dynamics. We are coming off a 40-year-plus cycle of low interest rates. As you develop projects, do you worry about the hike recently in the Treasury yield curve and cost of capital?

MR: MEANY: The short answer is yes. It has been offset somewhat by margin compression from the banks. The bank market is very competitive, so LIBOR has gone up, but the spread above LIBOR has been narrowing. In the longer term, it is something that we all have to watch closely.

MR. GOARMON: Bernardo Goarmon, CFO of EDP Renewables North America. You addressed the growing number of corporate PPAs. There is no question that a corporate PPA is preferable to a hedge. Where we sometimes struggle is with credit risk. Fifteen years are a long time. How do you think about credit risk when evaluating a corporate PPA versus a hedge? No one worries about the creditworthiness of the big banks that are the hedge counterparties.

MS. BEANE: Our risk group has taken a much harder look at the credit issues and risks associated with the corporate market. There isn't a long history with corporate PPAs, and we have all seen profitable companies diminish overnight.

We have been out of the tax equity market since 2008. We are moving back into it. The banks that are tax equity investors may have more experience evaluating corporate credits.

MR. GAYNOR: It is a huge issue. Most of the corporate solicitations that have hit the street have been with investment-grade offtakers. There may have been one or two non-investment-grade, but we have not been faced yet with the dilemma of landing a great PPA from a double-B credit and having to choose between that corporate PPA and a hedge with CitiBank or JPMorgan. Hopefully the investment-grade appetite remains so that we do not have to cross that bridge. It is a significant issue. ◎

What Next After Ontario Cancels Power Contracts?

by Crae Garrett in Calgary, Alison Babbitt in Ottawa, and Andrea Brewer and Matthew Bernardo in Toronto

Recent headlines have captured the decision of the newly elected Ontario provincial government to cancel more than 700 renewable energy contracts in the province.

For most of these projects, the approval of the Independent Electricity System Operator or IESO — the provincial entity responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario — had not been finalized.

The provincial government has explained that not all projects were cancelled, but rather the cancelled projects were chosen because they had not met their respective developmental milestones. The government's view is that the cancellation of the projects will decrease hydroelectric rates in the province by 12%. The provincial Minister of Energy, Northern Development and Mines, Greg Rickford, said that $790 million will be saved.

Here is our dissection of the recent decision and its potential impact on the development of renewable infrastructure in Ontario.

Partnerships between governmental authorities and the private sector for development of renewable energy infrastructure usually see the private partners providing the upfront capital to develop a project and bring it to commercial operation, after which the costs are recouped from payments to the private partner from the government. Such arrangements shift the risk of lengthy and over-budget construction to the private partner.

Policy U-Turn

The previous Ontario government enacted a "Green Energy Act 2009" in an effort to source 50% of Ontario's energy from renewable energy. The previous provincial government underwent several procurement processes, such as the feed-in-tariff (FIT) procurement agreements, which tried to offer stable prices for energy sourced from renewable energy. The procurement strategy used standard-form contracts. Suppliers would apply for a contract with the government. / continued page 22

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fuels of $24 a metric ton of carbon dioxide equivalent emissions starting in 2020. The rate would increase each year by inflation as measured by the consumer price index plus two percentage points. The tax would have to be paid by the owner of the fossil fuels at the point of taxation. That is the point of sale for natural gas used in a power plant. It is the mine mouth or coal wash plant for coal. It is the refinery for petroleum products.

The IRS and Environmental Protection Agency would report annually on emissions from use of fossil fuels. The goal is to reduce carbon dioxide emissions by 27% below 2005 levels by 2025 and by 29% by 2030. If emissions are not on track to reach these levels at two-year intervals starting at the end of 2022, then the tax rate would increase by another $2 per metric ton.

The tax paid would be refunded in two situations. Manufacturers who incorporate fossil fuel into products in a way that the emissions will be reduced or eliminated would be able to get a refund of the taxes paid on the fuel. Refunds would also be paid to fuel users who sequester the emissions or use the fuel for enhanced oil recovery.

Second, taxes would be imposed at the same rate on industrial process greenhouse gas emissions by certain categories of fuel users. The categories include iron and steel mills, underground coal mines, refineries, cement and petrochemical plants, aluminum smelters, semiconductor manufacturers and "electrical transmission and distribution" companies. A facility would have to emit more than 25,000 metric tons a year to be subject to tax. The tax would have to be paid by the "owner or operator."

Third, taxes at the same rate would have to be paid on non-fossil-fuel greenhouse gas emissions by manufacturers of eight products. The products include fuel ethanol, biodiesel and "solid biomass fuels." In the case of biomass fuels, the tax / continued page 23

Ontario

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Another such program, the large renewable procurement — called LRP — was launched in 2014 with the goal of attracting bids from projects of more than half a megawatt in size. The goal of these procurement strategies together was to assist Ontario in meeting its target for renewable energy.

A successful applicant to either program would receive its contract from the IESO. After the applicant (now the supplier) received its contract, but before construction could begin, the supplier would need to obtain the relevant approvals and permits. Once these were obtained and any milestones were met, then the supplier would need permission to proceed with construction. Once the supplier's facility was built and producing energy, then the IESO would pay the supplier for this energy at the contract price for a term that could reach up to 40 years in some cases.

Ontario has cancelled 758 power contracts with renewable energy projects. Some projects were already under construction.

The monetary incentives provided by the province to promote green energy are seen by some to have contributed to increasing energy prices for Ontario residents. In the lead up to the 2018 provincial election, there was a lot of talk about the increasing price of electricity. During this time, Doug Ford, Ontario's premier, announced that he would decrease hydro bills by 12% if he were elected.

Affected Projects

Following on the promises made during the provincial election campaign, the newly elected Ontario government has cancelled 758 renewable energy contracts. Among the LRP contracts on the list of pending cancellations are hydroelectricity, solar and wind projects. Among the FIT contracts are solar, renewable biomass, biogas and waterpower projects, but the vast majority are solar.

Most of the projects targeted had not yet received their notices to proceed from IESO.

A compensation scheme for one of the cancelled projects has been laid out in a bill that was enacted as the Urgent Priorities Act on July 25. The compensation scheme contemplates paying the developer behind the project for reasonably incurred expenses related to the project (specifically in relation to developing and acquiring the land, employee termination, subcontractor and landowner losses, as well as any decommissioning fees), certain debt and make-whole amounts, and any additional amounts prescribed in the law.

The most recent iterations of the FIT and LRP standard-form contracts contain language that give the IESO a unilateral right to terminate the contracts before projects reach commercial operation.

The change in policy position has some commentators questioning whether international investors in renewable infrastructure will continue to be attracted to investing in Ontario.

Compensation

It will be interesting to see what, if any, compensation will be made available to other developers. It may be that the government intends to compensate the developers to maintain public confidence in investments in Ontario.

As Bruce Pardy, a professor of law at Queen's University and author of the CCRE commentary "FIT to be untied," explains, the developer "assumes that legally granted and valid approvals will be honored at any time and also in the event of a change of government. Anything else would send out a fatal signal to the entire economy. The protection of confidence is a great asset and will certainly not be called into question by the new government either."

The obvious concern for developers and investors with projects in Ontario is the possible chilling effect on entering into contracts with the Ontario government.

A government counterparty is generally seen as attractive, given that as a general rule, they are reliable partners with ample means to pay. It remains to be seen whether the Ontario government's actions change investors' views on that. Similarly, contractual confidence is a substantive factor when rating agencies grade investments, and any decrease in confidence typically translates sooner or later into a decrease in rating and an increase in the cost of borrowing.

What Next?

The government has to be well aware of the risk that this course of action poses to the private sector's confidence in the government's commitment to its contracts and its perceived creditworthiness and, as such, will go to great lengths to ensure that developers in these situations will not be left out of pocket.

The government may be seeking to provide a formula for compensation that fairly represents developers' efforts and willingness to contract with the government, recognizing that renewable energy is only one of several industries in which private parties enter into development contracts with the government, particularly in Ontario.

Conversely, if the question of compensation is not adequately addressed in the broadest sense, then the risk of wide fallout and a plethora of unforeseen consequences is very real.

The effects of this decision will echo beyond the energy industry. Ontario has a number of public-private partnerships that have long-term contract terms. These PPPs are used to build roads and hospitals and schools within the province. However these agreements are predicated on an ongoing relationship between the government and the private sector.

The industry awaits clarity from the Ontario government as to how it will demonstrate to investors that they can continue to invest confidently in Ontario and the extent to which equity partners in existing LRPs and FIT contracts will be compensated.

It is not clear whether some of the issues will eventually spill into the courts, a process that can take years to reach resolution. ◎

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would be collected from the power plant owner or operator. The power plant would have to emit more than 25,000 metric tons of CO2 a year to be subject to tax.

The bill offers a variety of carrots in an effort to win political support. It would prevent the Environmental Protection Agency from regulating greenhouse gas emissions from facilities that are subject to the carbon tax. It would repeal federal excise taxes on gasoline, diesel and aviation fuels. It would allow companies to offset any payments they have to make at the state level on account of the same emissions, but under a sliding scale that would start at full credit in 2020 and then drop to 80%, 60%, 40% and 20% credit in each of the next four years.

Imported fossil fuels, ethanol, biodiesel, biomass and other covered products would be subject to a tax at the US border to eliminate any competitive advantage.

Meanwhile, Canada is having to modify a planned backstop carbon tax so as to avoid crippling Canadian manufacturers after the US imposed import tariffs on various Canadian goods, rolled back US environmental regulations and reduced the US corporate income tax rate to 21%.

Canadian provinces have until the fall to submit plans for reducing carbon emissions. Provinces that fail to adopt plans by the end of 2018 will be subject to a national carbon tax that starts at C$10 a metric ton and increases to $C50 a metric ton by 2022. The Trudeau government announced plans in late July to ease the burden. Only excess emissions above a specified industry average would be subject to tax. The starting point for measuring what is considered "excess" was originally 70% of average emissions for the particular industry sector. The threshold will be increased to 90% for industries that are subject to significant international competition from countries where there is no carbon tax, and to 80% for other industries. / *continued page 25*

Turkey Eyes Offshore Wind

by Ekin Inal, in Istanbul, and Ali Donat, in London

The Turkish Ministry of Energy launched a tender for the country's first offshore wind power plant on June 21. The deadline for bid submissions is October 23.

The plant will have a capacity of 1,200 megawatts. Saros and Gallipoli located in the Aegean Sea and Kıyıköy in the Thrace (on the coast of the Black Sea) were named as the possible locations for the plant. Grid connection points will be detailed in the tender specifications. These locations are close to Turkey's industrialized regions.

Turkey is expected to offer up to $80 a MWh for 1,200 megawatts of offshore wind.

The complete details of the project will be set out in the tender specifications, which have not been made public. Interested bidders will have to submit a bid bond in the amount of $20 million to participate in the tender. The winning bidder will have to submit a performance bond of $100 million.

The ceiling tariff for the project is set at $80 per megawatt hour. The winning bidder will be selected through an underbidding procedure. The power purchase agreement awarded will not have a fixed term, but will be for the period it takes for the plant to generate 50 terawatt hours of electricity once the plant is in commercial operation. Before releasing the tender, the Ministry of Energy said that 60% of the equipment will have to be domestically manufactured and 80% of the employment will have to be Turkish citizens.

This will be the country's third renewable power plant developed under a "renewable energy resource area" scheme (YEKA). The scheme involves allocation of land by the government for large-scale renewable energy projects to be developed by private-sector sponsors. Previously in March 2017, a consortium comprising Hanwha Q Cells and the Turkish Kalyon Group won the tender for a solar power plant of 1,000 megawatts, with the winning offer of US$69.90 per megawatt hour. In August 2017, a Siemens-led consortium, including Turkish companies Türkerler and Kalyon Enerji, was awarded the tender for a 1,000-megawatt wind power plant for US$34.8 per megawatt hour.

As of June 2018, Turkey has 232 wind power plants (both licensed and unlicensed), with a total installed capacity of 6,671 megawatts. Wind energy makes up 7.7% of the country's power generation.

WindEurope, a Brussels-based trade group formerly known as the European Wind Energy Association, underscores Turkey's potential for wind power, and says that its deep waters offer great potential for floating offshore wind technology.

According to the Global Wind Energy Council data, the United Kingdom leads the offshore wind market with an installed capacity of 6,800 megawatts. Germany and China follow the UK, with respective installed capacities of 5,300 megawatts and 2,700 megawatts. The offshore wind market moves full throttle and it remains to be seen whether Turkey will be able to position itself as a major player in the global market. ◎

Depreciation Bonus Questions Answered

by Keith Martin, in Washington

Depreciation bonus regulations that the IRS issued on August 3 answer a number of questions that have been coming up this year in M&A and tax equity transactions.

The regulations are merely proposed, meaning they may not be the final word. However, the IRS gave companies the option to follow them as if they are currently in effect. The IRS is collecting comments in the meantime. Comments are due by October 8.

Background

The tax reforms last December allow the full cost of equipment to be written off immediately rather than depreciated over time. This 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 — 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. */ continued page 26*

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Saskatchewan has sued to block the program. Doug Ford, the new Ontario premier, said in July that Ontario will join with Saskatchewan in that effort.

CRYPTOCURRENCIES could come up in IRS audits.

The IRS launched a new taxpayer compliance campaign aimed at cryptocurrencies on July 2.

Cryptocurrencies are treated currently as property rather than currency for US tax purposes. (For more detail, see "Bitcoins" in the April 2014 *NewsWire*.) This means that anyone holding bitcoins, ethereum or other cryptocurrencies risks having to pay a tax on gain when the coins are used in the same manner as if the holder sold property and used the cash to buy goods or services. This makes it impractical for individuals and businesses to use such currencies for ordinary course transactions because of the need to track gains and losses.

Karl Walli, a lawyer in the office of tax policy at the US Treasury, told a New York State Bar Association tax section meeting in June that the Treasury has a growing list of issues with cryptocurrencies that need to be addressed. However, it has to make guidance on the new tax reforms that were enacted at the end of 2017 a priority this year.

Taxpayer compliance is low. Credit Karma Tax, a free on-line tax preparation service, reported that fewer than 100 of the 250,000 tax returns that it filed in January reported owning cryptocurrency for tax purposes, a far smaller percentage than the 7% of Americans that are believed to own such currencies, and only one reported a gain or loss despite the huge swings in bitcoin prices during 2017.

Money raised in initial coin offerings may be taxable upon receipt by start-up blockchain companies if the companies are viewed as selling property or prepaid services. This creates a timing issue */ continued page 27*

Depreciation Bonus

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A depreciation bonus has been available at different levels since late 2011. 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 IRS answered a number of technical questions that modelers have been asking in M&A and tax equity transactions.

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

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

Bidders in M&A deals have been asking this year whether this step-up depreciation can be taken entirely in the year the partnership interest is purchased. The IRS said yes, "depending on the facts and circumstances."

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 plans to treat each partner as if the partner owns a percentage interest in the partnership assets directly. This means that a partner who has a 30% interest in a partnership that increases to 50% by buying an additional interest from another partner can claim the bonus on any step-up depreciation on the additional 20% interest. The buying and selling partners cannot be affiliates.

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

Tax Equity Issues

In tax equity partnerships, the developer is sometimes 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, with both the developer and investor then contributing their undivided interests to the partnership.

If the project was already in service before either type of contribution, then depreciation on the asset must be split between the partner making the contribution and the

Buyers in the M&A market can immediately deduct the full purchase price paid in acquisitions.

partnership based on the number of months that each owned the asset during the year of contribution. The depreciation for the month in which the asset is contributed belongs to the partnership.

However, the proposed regulations take a different approach for the depreciation bonus in one situation. In that situation, the IRS said the entire bonus belongs to the contributing partner and remains outside the partnership. That situation is where one of the other partners owned an interest in the project before the contribution and the property is contributed to the partnership in the same year it is put in service.

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

Putting these two principles together, suppose a tax equity investor comes into a project by paying the developer directly for an interest in the project after the project is in service. The *developer* would not be able to claim any depreciation on the share of the project considered sold to the investor. The *investor* should be entitled to a bonus even if the project was already in service. A bonus can be claimed on used property. However, any such bonus would remain with the investor outside the partnership because one of the other partners — the developer — owned an interest in the share of the project sold to the investor in the same year.

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, / continued page 28

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because the blockchain platform is usually still under development. The costs to develop the platform are incurred over time. US companies are no longer able to carry back losses to offset income reported in the past after the tax reforms last December.

An investor who paid $25,000 in January for 208,333 Latium tokens, a new cryptocurrency, has sued the Latium founders, after the token value dropped to $10,000, on grounds that the initial coin offering was a sale of unregistered securities in violation of US securities laws. The suit was filed in early June in federal district court in New Jersey. The case is *Solis v. Latium Network, Inc.*

Meanwhile, WePower, an energy financing and trading platform that uses blockchain, went live in July. Conquista Solar, a solar developer, plans to use the platform to auction energy tokens for 20% of the output from six 50-megawatt solar plants that it plans to build in Spain, as a way of raising development capital for the projects. Bidders can resell the tokens rather than take delivery of the power.

US INSTALLED WIND CAPACITY was 90,004 megawatts at the end of June.

Another 18,987 megawatts of projects were under construction and 18,806 megawatts were in advanced development. The figures are in the most recent market report issued by the American Wind Energy Association. One of the advanced development projects, the 2,000-megawatt Wind Catcher project, was cancelled in July after American Electric Power failed to get approval from Texas regulators for the proposed cost recovery plan.

Investment in US wind projects during the first half of 2018 was up 121% compared to the same period in 2017 as developers scramble to get projects into service ahead an end of 2020 deadline to qualify for federal production tax credits at the full rate.

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Depreciation Bonus

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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.

Finally, the proposed regulations also address some issues in leasing transactions.

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 proposed regulations addresses this issue.

Suffering From Lack of Transmission

Lack of transmission is quickly becoming the number one issue for renewable energy. A growing chorus of developers is complaining that projects can be built, but there is no way to move the electricity. Massachusetts had to import LNG from Russia last winter because of inability to get electricity across New England. Years of effort to build a proposed 720-mile Plains and Eastern transmission line have led so far to naught. Is transmission a growing problem in fact, and is there a way out?

Four panelists talked about the growing problems in this area at the 29th annual global energy and finance conference in June. The panelists are Rob Gramlich, president of Grid Strategies, Blake Nixon, CEO of Geronimo Energy, Himanshu Saxena, CEO of Starwood Energy Group, and Todd Singer, CFO of Transmission Developers, Inc. The moderator is Ike Emehelu with Norton Rose Fulbright in New York.

MR. EMEHELU: Rob Gramlich, you have spent at least 15 years working on transmission issues. Put the discussion we are about to have into context.

MR. GRAMLICH: Interest in transmission is cyclical, but it is not as if transmission suddenly came out of nowhere to become a big issue.

When I was hired by the American Wind Energy Association in 2005, the executive director at the time, Randy Swisher, told me transmission was the wind industry's biggest long-term issue. It was starting to emerge as an issue. There was already a lot of congestion.

We undertook at the time a study with the US Department of Energy about how transmission would be affected if wind reached 20% of the US electricity supply. Andy Karsner, who was the assistant energy secretary for renewables at the time, got President Bush to say we could make 20% wind a goal, but it was clear that transmission was the biggest barrier. All the utility participants in the process said, "I don't know how we can do more than 5% or 10% wind. We are going to need a lot of transmission."

We went to the biggest transmission owner in the country, American Electric Power, and put together with it a grand grid vision of how to do it. There are multiple ways to do it, but we put out one.

After that, FERC Order 1000 came out, Texas CREZ happened, the Southwest Power Pool's highway-byway happened, priority projects were developed, and MISO in the upper Midwest put multi-value projects in place. A lot of transmission was built. I think putting out the grand vision helped to some extent. We had one model, which was regulated transmission lines with the costs allocated broadly among all users of the grid.

Today, we are still building a lot of wind and some remote solar, but we are not building the next round of transmission lines to move the additional electricity. That is leading to more congestion and curtailments.

A new direct-current technology has emerged in the meantime that is cost-effective and valuable, and the economics, engineering and physics are great. The challenge is getting permits to build new transmission lines.

MR. EMEHELU: That's a good segue. It reminds me of a developer who spent $250 million over seven years to build a line from Canada south through New Hampshire, only to have it cancelled this year. Todd Singer, that's your business. You have transmission in your name. Why is it so hard to build new transmission?

MR. SINGER: The challenges are first getting someone to pay for it and then permitting and siting. You just mentioned the Northern Pass project. It is very hard to build overhead transmission lines in the Northeast.

What we are doing is building 2,000-megawatt projects with high-voltage dc lines buried underwater or underground. We have had success permitting those, but even then it is not easy. New York requires multiple permits. There is an article 7 permit that is the all-encompassing state-siting and environmental permit. There is a US Department of Energy presidential permit. Then there is a US Army Corps of Engineers permit. That's just at the federal level. In Vermont, for example, we needed another 13 state-level permits.

Each permit requires community outreach. Before we filed for any permits in Vermont, we spent a year having meetings with political folks, community boards, local stakeholders and environmental groups. We had something like 200 to 250 meetings before we even filed for a permit.

Time and Cost Ratios

MR. EMEHELU: Himanshu Saxena, why is this so difficult?

MR. SAXENA: We are a firm that does different kinds of investments. Transmission is one. We / continued page 30

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US INSTALLED SOLAR CAPACITY was 55,900 megawatts at the end of the first quarter 2018.

GTM Research expects 2018 installations to remain flat: roughly 10,800 megawatts compared to 10,600 megawatts in 2017.

Some developers who failed to take tariffs into account in their bids to supply electricity are expected either to cancel projects or delay them to buy time to renegotiate power contracts or to wait out scheduled tariff reductions.

Fifty-five percent of new generating capacity added in the US during the first quarter this year was solar. Solar led other generating sources for a second quarter in a row, according to the Solar Energy Industries Association.

THE CONSTRUCTION-START rules for wind farms are under attack from the coal lobby.

Senator Rand Paul (R-Kentucky) urged the US Treasury secretary in a letter in May to consider four ideas that would help offset the "unfair advantages" that he said wind has over coal.

One proposal is to accelerate the deadline to complete projects to qualify for federal tax credits. Wind farms had to be under construction by the end of 2016 to qualify for tax credits at the full rate. Projects that started construction in 2017 qualify at 80% of the full rate and in 2018 qualify for 60%. It is not enough merely to have started construction in time; there must also be continuous work on the project after the year in which construction starts. However, the IRS does not make developers prove such work on any project that is completed within four years. Paul wants to reduce the period to two years.

Many large wind companies stockpiled equipment as a basis for treating projects in which this equipment will be used as under construction in time to qualify for tax credits, but without knowing for sure in which projects the equipment will be used. Paul wants to bar the ability / continued page 31

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have built wind farms, solar farms, biomass projects and two large transmission projects — Neptune and Hudson — that are high-voltage direct-current lines.

We are in the middle of developing and, hopefully building soon, the Delaney transmission line in California that we were awarded three years ago in a competitive solicitation. It is a 114-mile 500-kilovolt line that will move electricity from a Colorado River substation in Arizona to the Delaney substation in California.

The project should take us four years to develop and one year to build. That ratio is really a problem.

When it takes you four times as much time to develop a project as to build it, then there is something structurally wrong with the system. The amount of money that it takes to develop a project is also a problem. I can't share the exact numbers for Delaney, but if a project costs $100 to build and you have to spend as much as $50 to develop it, that is a problem.

Development cost is about 5% of the construction cost for wind or solar, but as much as 50% for a transmission project.

The ratio of development cost to construction cost is higher in the transmission sector than in any other sector. If we develop a wind farm, it will cost $300 million to build, and our development costs are maybe $5 million or less. Solar is the same. For every other technology, it is generally around 5% or less of the development cost compared to the construction cost.

In transmission, those numbers reach as high as 50%. For private capital where you have significant risk — if a permit does not come in or you cannot find an offtaker — the development capital is lost. Who is willing to take that much risk for a possible pot of gold at the end of the rainbow? The amount of capital available for investment in such projects is very limited.

We have been focused on projects where we can get from point A to point B not in 20 years, but hopefully in 10 years or less. The Hudson transmission line that we built had been in the making for 15 years.

We have a running joke in our office. When somebody in his or her 30's picks up a new transmission project, we say, "We will build this before you turn 50."

I think that is a problem.

MR. SINGER: I can attest to that. We are a totally different company, but we say the same thing.

MR. SAXENA: I think that is a problem. We are seeing an effort in Washington to streamline the permitting process. Hopefully the effort will remain after the current administration is gone. The interim period while the government tries to fix its policies has actually made it more difficult because while we are in line looking for certain permits, the government workers have to divert attention to figure out what the new policies mean coming out of Washington.

Ironically, the effort to help has actually slowed down development, not helped it, which is a challenge. We see the same thing with agencies like WAPA, the federal transmission agency in the West. Everyone is trying to figure out what Washington really wants. So this period when the administration is trying to help is actually not having the intended affect.

We have about $1.4 billion in capital that we need to put to work over the next two years. That is fresh capital that we have just raised. If we can successfully do one transmission project, I think it will be a good day. We would love to do 10 of them, but there just are not enough opportunities that can be executed over the next 10 years.

Transmission is a very, very long game.

No Leadership

MR. NIXON: I can recall two or three other major plans that came out during the period to which Rob Gramlich referred to build new transmission in various parts of the country, but they all relied on top-down approaches. They were the product largely of federal planning. You get into federalism issues between federal law and states' rights.

I second what Himanshu Saxena said. Take MISO as an example, as that is the area in which we are most active. The multi-value project process has been fantastic. It worked very well.

The problem is it took 15 years from start to finish. The new lines that are not fully built yet are already fully subscribed and then some. And there is no MVP-2 behind it. There are something like 40,000 megawatts of new generating capacity in the interconnection queue, some crazy number. Developers like me are throwing money at the process, just trying to get projects ready to go, if and when there is a way to move the electricity to market.

Think about the pace at which our industry is changing at the wholesale power market level, and think about the process and all the fiefdoms and infighting that exists within the grid system. It just is not set up for success at this time.

I would like to think that there is some federal leadership that is willing to do somewhat crazy, somewhat outside-the-box things — consequences-be-damned kind of leadership — to . . .

MR. EMEHELU: I think that's in place. [Laughter]

MR. NIXON: I was leading the response, yes. [Laughter]

MR. EMEHELU: It sounds like a lot of this is a regulatory problem. We have about two million miles of pipelines for natural gas in this country. With transmission lines, we have just over 200,000 miles. The difference is the federal government helps push through gas pipelines, but for transmission lines, you have to go to the states and even to counties.

Rob Gramlich, you just flew up from Washington this morning. Is there real movement to fix this?

MR. GRAMLICH: The report on transmission from Washington is, unfortunately, I do not see a lot of change coming soon.

Himanshu, you mentioned some of the federal coordination. I do not see action being taken by the current administration to resolve disputes and speed up permitting. The FAST Act that was enacted just before / continued page 32

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to shift equipment to a different project.

Paul said the IRS has been too liberal about what physical work is considered significant enough at the project site or a factory to qualify as the start of construction. He wants the Treasury to "require work significantly beyond the current minimal standards."

Finally, a complaint from power plant owners who use coal and other fossil fuels is that wind farms have an incentive to sell electricity into organized markets even at negative prices. Any sale entitles the project to production tax credits on the electricity output of as much as $24 a megawatt hour. Paul wants the IRS to deny tax credits on electricity sold at negative values.

SOLAR PANEL PRICES are expected to fall 34% by year end to a global average of 24.4¢ a watt, according to Bloomberg New Energy Finance. GTM Research is projecting a 31% drop to an average of 27¢ a watt.

These figures are before imposition of US import tariffs.

Roth Capital Partners reports that US spot prices for high-efficiency PERC modules that are able not only to absorb direct sunlight, but also to soak up scattered and reflected light on the back side were 42¢ to 47¢ a watt in mid-July, with prices expected to fall to 41¢ to 45¢ by the fall.

Some developers are delaying purchase orders to take advantage of falling prices.

Chinese solar panel demand is expected to drop to 28,800 megawatts compared to 53,000 megawatts in 2017, according to the latest estimate by GTM Research, down from estimates from other experts in June for Chinese demand in the 30,000- to 35,000-megawatt range.

The Chinese government, in a surprise move on June 1, scaled back central government support for utility-scale solar projects and placed a low cap on distributed solar deployments this year. It / continued page 33

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Trump took office set up a new process. On paper, it looks good, but my understanding is it is all gummed up. They cannot agree on governance. There is no break in the logjam from where it had been.

That is the administration side. On the federal permitting side, for private lands there is federal back-stop siting, but it is very limited. The courts have limited it. It is not a dead letter. Some of us in the clean energy sector have encouraged the administration to use its authority to push through transmission projects. However, the indications to date from the US Department of Energy is it has no interest in doing that. Maybe that will change. We are not giving up.

The third leg is what the Federal Energy Regulatory Commission can do to promote more transmission, and I think there is an opportunity there. Nothing has happened yet. The new FERC commissioners took office late last year and earlier this year to a big backlog that built up while the commission had too few commissioners to have a quorum. Now grid resilience is all the talk. There is a strong argument to be made that transmission helps resilience.

FERC could, under the mantra of resilience, step in and do more, but thus far, transmission is not on the agenda. I know a lot of folks here are interested in investing in private transmission in a merchant direct-current model as opposed to the more utility-based model where the utilities do it and throw it in rate base.

FERC has a big role in that. Order 1000 opened the door to competitively bid projects. That is a very controversial policy. There is no reason these new FERC commissioners have to say that they even want to continue that.

My sense is that they do support the general structure of third-party transmission, and I think they believe that it can work. It worked in Texas CREZ, for example. But it is not working well in most of the parts of the grid serviced by RTOs. There are very powerful interests lobbying Congress and FERC to say, "Let's kill it. It is broken."

I don't think FERC will kill it. I think it will take a serious look and try to fix the process. My concern, from a clean energy perspective, is the utilities ultimately still have so much power over the RTOs. RTOs are voluntary institutions. We are not going to see much new transmission built if the utilities do not get to put it in rate base.

They were pretty excited about transmission 10 years ago when they got to put it into their formula rates with a nice return on equity. When it is not theirs, they do not care about promoting it, and these projects require significant political support to get through the stakeholder process to be approved.

MapQuest

MR. EMEHELU: Before FERC Order 1000, incumbent utilities had a right of first refusal to build and operate transmission lines within their service territories. Order 1000 removed that right of first refusal, so people like Todd Singer and Himanshu Saxena can go build lines. How has that actually worked in practice?

MR. SINGER: Let me talk about how we think about projects. Our Vermont line is a good case in point.

Vermont Yankee, which was a 620-megawatt nuclear plant in Vermont, announced in the fall 2013 that it would close. At the same time, government officials in eastern Canada and New England said they wanted to bring hydro power from Canada into New England. Put that together, fast forward three weeks, and my CEO and I are sitting in my office thinking about next projects. Blackstone wanted us to do another project.

We thought about duplicating the Lake Champlain leg of our line and then having it run somewhere into New England. The first question we asked was how it would work electrically. We looked at the ISO-New England system and where on the 345-kV system our line would work. It was clear it had to plug into the Coolidge substation in Ludlow, Vermont.

How then do you site such a project? We thought about where our Champlain Hudson Power Express high-voltage dc transmission line was exiting Lake Champlain in New York: in a town called Putnam Station. What is directly across from it, but located in Vermont? Benson.

Then how do we route it? We go to MapQuest. [Laughter] This is how a $1+ billion project actually gets sited. [Laughter] I am not kidding.

Go into MapQuest, and what is the route from Benson to Ludlow, Vermont? There were two choices. One went through these big green spots. We were like, "What are those green spots?" "Oh, they are national forests." {Laughter] We do not want to deal with that.

The second route does not go through the national forests, and that is our route. Ninety percent of that route is exactly the same. From that point on, you start to look at the economics of the project and then you start the whole permitting and outreach cycle, and it goes on from there.

MR. GRAMLICH: So there was no bid? ISO-New England did not say, "We want a line from A to B and we are going to take . . . ."

MR. SINGER: It is a merchant line. It still is, and it was started because of the signals from Canada and New England. There was a prospect of RFPs. The economics worked purely from an arbitrage basis. Then, as with all development, you figure it out from there, and we are still working on it.

MR. SAXENA: All right, so he is making it sound easy. I would say don't try it at home. This is for the experts. [Laughter]

MR. SINGER: It is easy to start.

MR. SAXENA: We have a lot of global investors, sovereign funds and others. They call us and say, "We have this great transmission development opportunity in the West. Should we do it?" And we say, "You are sitting in Asia. I can barely build a transmission line in California sitting in New York. You cannot do it from Asia."

He is making it sound easy. He has a special version of MapQuest, right? [Laughter] Can I get a subscription to it? Just send me your password.

We are doing the routing for a transmission line right now, and a certain agency is making us study five different routes. All five look really good on MapQuest . . . [laughter] . . . but we are spending millions of dollars studying every single route.

MR. SINGER: I will say our Vermont project was a lot different than our New York project from a siting perspective. Vermont was much easier. New York, not so much.

Market Shifts

MR. SAXENA: Stay out of New York, too. That is another rule of thumb. I think all of you know this already, but there are two business models, from my perspective, in this sector. One is where you build a regulated transmission line, which is what we are doing in California. Once we build it, it will be considered part of the California ISO system, and we will get a regulated rate of return.

We will be considered a utility in California, so we will have all the rights and powers that come with being a utility. I used to work for AEP back in the day, so I have a utility heart and a private equity head.

The other model is what we did with the Neptune and Hudson transmission lines, which are what we call merchant transmission lines, which is what Todd Singer is doing, where you build the line for a customer. In our case, we have New York Power Authority / continued page 34

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had already stopped issuing permits for new solar facilities in parts of the country where existing plants are sitting idle due to grid congestion.

COMMUNITY CHOICE AGGREGATORS in California bought 57.1% more electricity from wholesale suppliers in the first quarter of 2018 compared to the same period in 2017, according to an S&P Global Platts analysis of filings with the Federal Energy Regulatory Commission.

CCAs are county-level entities that buy electricity and supply it to county residents.

The FERC data covers power sales by 20 power suppliers to 10 CCAs. A year ago, FERC filings showed only 13 power suppliers and five CCAs.

Silicon Valley Clean Energy was the biggest purchaser, accounting for 39% of total purchases. Marin Clean Energy was second at 15.9%.

Exelon was the biggest supplier, accounting for 36.5% of total sales. It sold power to seven of the 10 CCAs.

Six new CCAs have launched this year, bringing the total number in California to 18. The staff of the California Public Utilities Commission estimates that as much as 25% of the electricity load in California will have shifted to CCAs and other suppliers by the end of this year, increasing to as much as 85% by the mid-2020s.

Meanwhile, the utilities commission has been wrestling with what exit charges to require customers who abandon the regulated utilities to pay to help cover the cost of stranded assets that the utilities are left holding.

A final decision is expected in September. The CCAs will be permitted to prepay the exit charges on behalf of their customers on a one-time basis in order to be relieved of the burden going forward.

Deanne Barrow, a Norton Rose Fulbright lawyer in / continued page 35

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and Long Island Power Authority as 20-year customers on our transmission lines.

Both business models work. If you can find a good route and you can find a good customer for whom you are solving a problem, those agreements can move fast. Permitting obviously always takes time.

On the other hand, when we won the bidding in California, we had a customer from day one, which was the California ISO, and that also works really well. FERC Order 1000 was designed to address the issue that utilities were not letting other participants like us play in their service territories. FERC Order 1000 has been in place now for 10 years. The group of projects was done in California. More than a dozen projects were awarded over the last several years. We got one of them. Now you see some other FERC Order 1000 RFPs coming out in PJM and other markets.

It is so much easier to manage a FERC Order 1000 RFP if you are in a single state because the cost allocation is simpler. With a multistate project, there is a fight among the states about who should end up paying for it. The whole cost allocation methodology is a big mess in the Northeast.

You have to come up with who is going to pay for the line at the same time as who will build it. Part of the reason why FERC Order 1000 has not been more successful is because there has not been a centralized way of allocating cost to different parties. Transmission is one of those asset classes where everybody wants it, but nobody wants to pay for it. That problem is structural.

The other challenge is the long lead times. If it takes 10 to 15 years to permit a transmission project, during such a long period, everything can change.

We saw this when I worked for AEP. The 735-kV lines that AEP was building from east to west were desperately needed, but by the time it got around to building them, the markets had shifted completely and the lines were no longer needed.

You see this in other places with coal and nuclear retirements, with distributed generation, with storage. The shape of the generating assets is changing far faster than the shape of the transmission assets. One is always playing catchup.

MR. EMEHELU: Blake Nixon, when you are committing to build a new generating facility, how do the transmission issues factor into the location, or are you more focused on finding the best wind resource or most predictable sunlight?

MR. NIXON: The ability to move any electricity we produce is number one, particularly in the wind business where the technology has improved so much that you can get decent productivity out of a lot of different resource sites. Historically, you would go to where the wind was and where transmission was readily available or you could get to it and there was some capacity.

But that has not been true for a number of years. I think lack of transmission will remain the big issue in the future. Finding the incremental pieces of existing capacity or anticipating the next addition of new incremental capacity is siting-job number one.

Then you go from there. You draw your concentric circles based on how big a project you plan to build and what the market opportunity is, and then you look for a site with the best resource within the desired radius.

Solar is a little different. It is a bit more plug-and-play. The constraints are different. I am not active in California, so I am not speaking about markets like that, but in the Midwest, the irradiance differences are not that different from one site to the next, so proximity to the physical infrastructure is what distinguishes sites.

Access to transmission is the number one challenge for siting and delivering projects. It is top-of-mind for us every day.

Black Stone

MR. EMEHELU: Let's spend a couple minutes on financing. Transmission projects are challenging to develop. They take forever. A lot of money has to be spent in early-stage development. How do you finance that? When do you go to lenders to put in money? Is all the development capital pure equity?

MR. SINGER: Blackstone is funding 100% of our development equity and, as Himanshu said, it is 100% at risk. Every three months, we have to ask them for money. Every expense is evaluated.

Once we have all of our commercial agreements in place, engineering, procurement, construction agreements, and we have all the permits, then we arrange outside financing to pay for construction.

MR. EMEHELU: Himanshu, Todd Singer has to squeeze money from a black stone. How do you fund it?

MR. SAXENA: I was listening.

Look, there is a lot of money in the system, right? We are selling Hudson right now, and we see tremendous interest in the market in buying and operating transmission assets. There is no shortage of capital looking for good-quality infrastructure assets.

Gas pipelines and electric transmission assets are core infrastructure assets. Once such an asset has been built, everybody wants it. The problem is getting to that point.

Development capital is not widely available. It takes a certain degree of foolish optimism to invest in transmission, and there are not many people who have that.

The cost of funding construction is coming down to a point where we are seeing wind farms being financed at LIBOR plus 99 basis points for one-year construction projects. Transmission can probably be financed at LIBOR plus 125. There is no lack of debt capital for good projects that are ready to start construction. Finding the development capital to get them to that point — squeezing a black stone — is the hard part.

MR. EMEHELU: Where do you see the transmission business going? Do you see new technologies, new financing structures, new regulatory solutions?

MR. GRAMLICH: The grid is aging. There are challenges connecting remote renewable energy projects to the grid. We have an extremely old set of transmission lines in this country that will probably be replaced mostly through the utility rate-base regime.

There could be opportunities for developers to do pieces of it. That is where new technologies come in. There are some technologies that could be used to get more capacity out of the existing lines. That is an opportunity for clean energy.

There are ways to benefit operating wind and solar projects using dynamic line ratings, power flow control, network topology optimization and other new technologies to reduce congestion and curtailment. You build a plant and then four other plants come into your area. You could not have forecast it. The new plants crush your prices or end up causing your project to be curtailed, and now you are looking for ways to maximize your revenue out of an existing asset, and you may not be able to build more transmission. These types of opportunities will be important.

MR. EMEHELU: We hear smart grid, smart grid, smart grid. Is this part of a smart grid?

MR. GRAMLICH: Most people mean retail and residential meters when they say smart grid. These fall more into the category of improvements to the bulk transmission system. We need a sexier term obviously.

MR. SINGER: The RTOs and utilities that operate and own the grid are not in the business of / continued page 36

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Washington who follows the CCAs, said that lenders and investors in private power projects that have power contracts to sell electricity to CCAs are aware of the risk that the exit charges could drive customers back to the regulated utilities.

While the commission's recommendations appear favorable to the CCAs, there is more to come. The commission will now turn to considering longer-term solutions to redistribute excess power supply held by the utilities. Several proposals are on the table, including allowing the utilities to securitize or borrow against a special rate component that would be added to utility bills and then use the borrowed funds to buy down the electricity prices in contracts with independent generators. These contracts would then be auctioned to CCAs.

GAS PIPELINES got a break from the Federal Energy Regulatory Commission.

Many gas pipelines are owned by master limited partnerships or MLPs. These are a form of partnership with ownership units that can be purchased on a stock exchange or secondary market. Like all partnerships, they do not pay income taxes. Rather, each owner or partner pays taxes directly on his or her share of partnership income.

The Federal Energy Regulatory Commission decided on March 15 that pipeline companies that operate as MLPs should no longer be able to pass through an income tax charge to customers as part of cost-of-service rates. The commission said it is inappropriate for such pipeline companies to charge customers for taxes they do not pay.

Various airlines and oil refineries had sued to stop the tax charges. A US appeals court ordered FERC to take another look at the practice in July 2016. (For earlier coverage, see "Court Orders FERC to Revisit Pipeline Charges" in the August 2016 *NewsWire*, "Taxes in Transmission / continued page 37

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taking risk. They are in the business of making sure that it is reliable. They are like baseball umpires. If you don't notice them, they are doing their jobs. If you notice them, they are not.

We heard some of this from the storage panel yesterday, but it's challenging to get utilities to move to new technologies. They are not compensated to take risk. It takes more time for improvements to be adopted in this sector.

I agree with what was just said about the aging infrastructure. The US grid is a patchwork quilt. Finding ways to fix the problems this creates is where the opportunities lie.

Changing Politics

MR. SAXENA: Things could improve as the Facebooks, General Motors and Googles of the world enter into more and more corporate PPAs. They are all looking for renewable energy. They want to put in data centers that are huge consumers of electricity. They are building a new data center every six months. They are starting to notice the lack of transmission capability on the grid.

How do you site a $1+ billion transmission project? By using MapQuest.

These are companies with enough pull within the federal government and the states to get things done. We have seen this at the state level where one of these big companies says, "I will put my data center or factory here if you will allow me to buy directly from this wind farm that is being developed next door." The states find a way to accommodate them because they want the jobs.

My hope is that 10 years from now when Amazon's market cap is $2 trillion and the company is more powerful than the federal government, Amazon will force a wholesale rebuild of the transmission grid.

When you start seeing forces like this demanding change, something will happen.

MR. NIXON: To take the historic and apathetic view that not much will change, I think it is all about use. It is like Rob Gramlich was saying: how do you squeeze more out of each transmission line? It is not just wind, not just solar. It is hydro in the Pacific Northwest. It coal-fired generation of the coal states. It is gas in Ohio and Pennsylvania.

Promoting renewables through subsidies can only go so far. Without the physical means to move the electricity, we end up with fragmented and inefficient markets. Solve the physical problem and you really have an opportunity for a truly free market.

I never heard that statistic that you mentioned at the beginning about two million miles of pipelines and 200,000 miles of transmission lines. That is insane, really. The fundamental problem is a failure to have a national approach to fixing the grid and overcoming a lot of local fiefdoms that stand in the way of a grid that works. I will keep saying that every time somebody asks me. That is really the solution. Build something that looks like an overlay, even if it does not include Texas, and let's create a real market.

MR. EMEHELU: Any questions from the audience?

MR. KIM: Jonathan Kim from Nataxis. Do you see any resistance coming from incumbent utilities to where you want to locate transmission? I am wondering if part of this is an issue of regulated versus not regulated and the opposing forces between them.

MR. SAXENA: The regulated utilities do not like people like Todd and me. We are a threat to their business model. I think there are certain markets, like California, where the utilities have learned how to live with independent developers. In other markets, there is considerable tension between the utilities and the non-utilities trying to build transmission.

That is not a significant reason for why new transmission lines are not being built, but that resistance is very much there.

MR. SINGER: I think the utilities tolerate us, as merchant developers, and our relationship is good.

MR. TONDU: Joe Tondu from Tondu Companies. So the solution seems to be federalism. What about the opposite? ERCOT works quite well. Why not make a bunch of state-regulated grids, say in Michigan, Ohio and Pennsylvania, that are completely outside the federal system? When the federal government put the grid in the hands of regional RTOs, it made things massively complicated. For example, now you have MISO, which operates part of the grid all the way from the east coast to the south coast. Why not go the other way?

MR. SINGER: Permitting of our New York project at the state level was lengthy, but it was thorough. The federal permitting duplicated some of what had been already done at the state level. I agree with you. Just eliminating overlap would be a big help.

MR. GRAMLICH: Nobody else is going to physically disconnect a state from the rest of the interconnected grid like Texas has done. It is just not going to happen. I think what you are getting at is whether there is a way to bypass some of the regional policy and FERC logjams and cost allocation debates. That is what the merchant DC model allows. Clean Line and other companies have tried to use that model with mixed success. Todd Singer is hopefully going to get his project done. ◎

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and Pipeline Tariffs" in the February 2017 *NewsWire* and "Pipelines and Partnerships" in the April 2018 *NewsWire*.)

When it ordered a halt to the practice in March, FERC asked for comments on whether it should require MLPs to make refunds to customers for taxes they already collected.

FERC said in a new order on July 18 that no refunds will be required, and it will not require the pipelines to reduce their rate bases by the tax overcharges, since doing so would violate a prohibition against retroactive ratemaking.

It reaffirmed its decision in March not to allow income tax charges to be passed through to customers, but called it a general policy that the commission will have to "fully support and justify" in individual cases. It said, "An entity such as an MLP pipeline will not be precluded in a future proceeding from arguing" that it is entitled to an income tax allowance if it can show that such an allowance will not lead to a "double recovery of investors' income tax costs."

The latest order can be found at 164 FERC ¶ 61,030.

ELECTRIC COOPERATIVES are concerned that they will lose their federal income tax exemptions because of the tax reforms that were enacted last December.

Electric cooperatives are legal entities, usually in rural areas, that are formed to buy electricity for their members. By pooling electricity needs, they may be able to bargain for better prices from suppliers. Most, but not all, electric cooperatives are exempted from federal income taxes under section 501(c)(12) of the US tax code. However, to maintain the tax exemption, at least 85% of their income each year must be collected from their members "for the sole purpose of meeting losses and expenses."

Rural electric cooperatives receive government grants for a variety of purposes, including installing broadband / *continued page 39*

Blockchain Comes into View

Bloomberg reported recently that "if utilities think solar panels and batteries are bad for business, blockchain should scare the bejeezus out of them."

Four blockchain pioneers talked at the 29th annual global energy and finance conference in June about what blockchain means for the power sector. The panelists are Thomas Folker, CEO of Leap, Michael Horwitz, a partner with Greentech Capital Advisors, Ernst Sack, a partner with Blue Bear Capital, and Kit Harrison, senior manager, North America, for the Green Power Exchange. The moderator is Noah Pollak with Norton Rose Fulbright in Washington.

MR. POLLAK: What are the main advantages of blockchain over what we do now? The technology is also called a distributed ledger.

MR. HARRISON: The approach today of using central servers leaves us one main point of failure, and the servers are expensive to run. A distributed ledger that acts as a record of transactions allows certain efficiencies. It allows peer-to-peer communication and eliminates the need for third parties and big data centers.

MR. FOLKER: The overhead of running a blockchain network versus a centralized one is minimal, and there are some other benefits to it as well. Security is one benefit. You can transact securely between peers without the need for an intermediary to verify transactions.

I like to compare it to the land register. If I want to buy a piece of land from you, I will go to a central register first to check whether you actually own the land. Then we register that transaction, and then everyone else can verify that I am now the new owner.

That process takes time. It is not very efficient, and if you replicate it to millions of devices, it becomes complicated.

With blockchain, you have a technology that has baked in the immutability and verification of that record in the ledger. No third party is needed to verify transactions. I can sell a house peer-to-peer or I can buy coffee from you if you have a coffee place, but the transaction overhead is minimal, and you can transact with millions of peers at fractions of cents. Anyone who worked at a utility knows how much it costs to change just one line item on a bill and knows that there are significant efficiencies to be gained by moving to a technology that handles everything.

MR. SACK: Before we dive into the topic, it is important to defuse some of the skepticism around blockchain as a concept, given how much hype it has gotten. It is also important to separate the discussion into at least two categories. There is cryptocurrency, and then there are discrete applications.

Regarding cryptocurrency, more than 1,600 different cryptocurrencies are now traded on exchanges.

Some people believe they will change the world, where we are tokenizing every asset in the universe. Others like Warren Buffet and Charlie Munger have famously said cryptocurrencies are like finding out your neighbors are trading turds, and you don't want to be left out of the action. [Laughter.]

What the other panelists are describing are more the discrete applications around supply chain optimization, field services, crypto or cyber security, and there we have real use cases that operators are embracing.

Current Uses

MR. POLLAK: Michael Horwitz, what are some of the applications for utilities or individuals that will change the energy markets?

MR. HORWITZ: A couple big ones involve electric vehicles. We have seen big European utilities and even some progressive US utilities look at using blockchain as a measurement and verification tool, as electric vehicle charging stations become more prevalent and multiple users on a daily basis are plugging into them. How do you meter and verify transactions on those systems, especially when you are talking about millions of US vehicles within the next decade? The autos are mini power plants driving around the roads and plugging into grids in any number of utility service territories.

The other big application — we are working with some Australian utilities on this — is how to use blockchain in deregulated markets in connection with wholesale trading of electricity.

Those two are very large potential applications today. The use of blockchain in wholesale trading is probably a bit more challenging given that the technology lacks the speed to transact on a second-by-second basis on that scale. Electric vehicle applications are high on my list of the most relevant.

MR. POLLAK: Ernst Sack, anything to add?

MR. SACK: There are several categories, but we might group them into field services, logistics and supply chain optimization, energy trading and cyber security.

The internet gave everyone access to lots of information.

What distributed ledger technologies and smart contracts deployed on distributed ledgers enable is sharing of assets and data.

Every asset — whether it is a turbine or a generator or a unit of power — can now have a unique identifier assigned to it. The network that is transmitting information about that asset can tell you in a cryptographically secure way who owns the asset, when did the owner take ownership, what price did the owner pay, what rights does the owner have to transmission, distribution and resale of the asset, and how can you engage with the owner to buy or use the asset?

That will allow, for example, tracking and certification of renewable generation or the provenance of parts you are buying to operate and maintain your facilities or tracking your employees. Have they passed the correct health and safety training? Are they certified to work in your jurisdiction and your business line?

MR. POLLAK: Kit Harrison, do you want to talk for a minute about the more specific applications on which the Green Power Exchange has been focusing?

MR. HARRISON: We have been trying to develop a peer-to-peer trading platform for renewable power. The goal is to allow people to buy renewable power directly from the producers and have it delivered to them. We are also developing a form of power purchase agreement to govern the transactions, and we are also trying to allow people to trade electricity like a commodity over the platform to benefit from arbitrage opportunities.

MR. POLLAK: Thomas Folker, Leap is also trying to build a platform on blockchain. To do what?

MR. FOLKER: We are a wholesale marketplace for distributed energy resources like electric vehicles, air conditioners, irrigation systems and anything else that is load controllable. Right now, we are engaged in demand response, which is the coordinated reduction of electricity demand. Once the Federal Energy Regulatory Commission or the grid operators allow it, we will also be acting as a generator or electricity supplier to the grid.

Peer-to-peer is a great concept that we think is a perfect application for blockchain.

We have to be mindful currently that we are still reaching customers through a physical grid. I am not going to install a cable between my neighbor and me to have our own personal grid. If you want to participate in a wholesale market today, you still have to work with the utilities and */ continued page 40*

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in rural areas, making energy efficiency improvements, and rebuilding after wild fires, tornadoes, floods and other disasters.

These types of grants have been viewed in the past as a form of capital contribution. However, the tax reform bill last December requires contributions by "any governmental entity or civic group" to be reported as income. The coops are concerned that this will cause them to lose their tax exemptions under the 85% test, the National Rural Electric Cooperative Association said in a letter to the House tax-writing committee chairman and ranking Democrat in early July.

The trade association is also asking Congress to clarify how rents that coops receive from leasing spare capacity on fiber optics lines affect the 85% calculation. The tax code lets coops ignore income from qualified pole rentals.

SOLAR TAX BENEFITS were allowed to two individuals on three rooftop solar installations after the IRS made a mistake.

Individuals usually have a hard time claiming investment tax credits and depreciation on solar equipment put to commercial use. Passive loss restrictions and at-risk rules make such benefits hard for them to use. First, individuals can only use such tax benefits against income from other passive investments, unless they are personally engaged in the business. Second, at-risk rules limit the depreciation that can be claimed to the amount of equity the individual has in the equipment.

A licensed contractor and lawyer who had been working on low-income housing transactions installed rooftop solar systems on a warehouse, a rental property and a residence in California in 2010 and entered into five-year power contracts with each of the property owners to provide electricity at a discount to the local utility rate. */ continued page 41*

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the grid operators. That's why we are part of a consortium, called Energy Web Foundation, in which many of our energy partners, like Shell and PG&E, are also active, that provides a standard to transact on blockchain without having to go into a fully peer-to-peer market that might not be regulated.

MR. HORWITZ: Something interesting that Thomas just touched on is the demand response market. PJM had a recent capacity auction that was a tipping point for how capacity markets will value demand response and energy efficiency in the future.

You measure and verify how much efficiency or demand response impact you had after the period. If you can use blockchain to measure the effects in real time, then you can dispense with mechanisms that both restrict these markets from developing fully and allow some utilities to game the system.

If you have a distributed way to measure and verify energy efficiency and demand response, then efficiency and demand response become more valuable alternatives to new generation.

In the most recent capacity auction, you had only about 300 megawatts of new generation clear, which is really incredible. The vast majority was efficiency and demand response, which says a lot about how these markets are changing. Blockchain can help identify the electrons and savings.

Effect on Utilities

MR. POLLAK: Should utilities see blockchain as another element of the utility death spiral? Or is it a net positive for them?

MR. HORWITZ: I don't buy into the utility death spiral. I think that was overplayed about six or seven years ago by an independent power producer CEO, who is no longer CEO of that company. But the utilities are different than 15 years ago when I was trying to help distributed solar companies break through into the US market and utilities were erecting obstacles.

Today, many big utilities are embracing distributed solar. The Energy Web Foundation is a perfect example of global utilities getting together to identify ways to harness distributed technologies. Most utilities have blockchain teams.

MR. FOLKER: The mechanics of the death spiral are largely driven by distributed generation. Blockchain or distributed ledgers accelerate the adoption of distributed generation because they lower the barriers to entry for participating in the trading and distribution of electrons.

If you can see a universal register of all energy that is being generated, stored, transmitted, where, when, how, at what price, at what clearing level, then it is easier to participate in that system, especially if the system is not centrally controlled by an oligopoly of utilities.

That said, a lot of these distributed generation resources will be owned by or be tied to strategic partnerships with incumbent utilities. There is no death spiral if there is collaboration, participation and ownership across that system.

Smart Contracts

MR. POLLAK: The implementation of blockchain requires something called a smart contract. Kit Harrison, can you explain what a smart contract is and how it differs from what the audience would think of as a contract?

MR. HARRISON: Contracts are if-this-then-that statements. With smart contracts, everything is codified so it is brought down into its truest if-this-then-that statement.

Smart contracts are difficult to read unless you speak code, so the main issue is getting an interaction between what the smart contract actually says and how people will be able to read and interpret it. The initial step is to load it on the blockchain.

MR. POLLAK: So a smart contract is a contract reduced to computer code. It transacts the transactions in real time.

MR. HORWITZ: Exactly.

MR. FOLKER: It is just a piece of JavaScript code, so I advise everyone interested in smart contracts to learn JavaScript.

It is helpful to understand how these contracts work. They are pieces of code that reside on ethereum, for instance, as a blockchain virtual machine. They are completely open. Everyone can see what the code does.

Once a smart contract is launched and active, no one can touch it anymore, and it is self-executing. It is a series of if-this-then-that statements. There might be a time delay. For instance, an electric vehicle that participates in our market might be called upon for demand response. We enter into a smart contract for the exact price and delivery time. We verify delivery by reading out the meter data, and if the asset actually reduced our load as agreed, then the contract itself executes and pays the electric vehicle owner.

MR. SACK: The governance of that smart contract ecosystem is critical to understand. It differs from one blockchain to the next. Just because we say smart contract does not mean there is no dispute resolution mechanism and no need for lawyers to interpret and enforce that encoded contract.

For example, the bitcoin blockchain is being governed by whoever controls 51% of the mining power, which is largely concentrated in a bunch of specifically hardware-engineered rigs in China. The Energy Web Foundation, or something like any of the 122 energy blockchain startups that are now in operation, may have six or seven strategic investors like a Siemens or a Centrica, or a number of the people in this room on their boards, who vote on which contracts are enforced and in whose favor.

There is high diversity in this ecosystem. You should understand how decisions are made before you commit your capital or your assets into a particular blockchain.

MR. POLLAK: Talk about timing. My understanding is that on the ethereum network, only seven transactions per second can be done. That's about 18 million transactions per month worldwide. It sounds to me like we are envisioning many, many more transactions than seven transactions per second. We could probably do that volume with the people in this room. What is the plan for being able to scale up blockchain technology in order to handle the volume that everyone hopes to see?

Crypto-Kitties

MR. HARRISON: The ethereum blockchain is public. Everyone has access to it.

The ability to scale comes from hosting a private blockchain yourself and being able to meet the computational demands in-house. It is still a distributed system, but it is not publicly all over the world, so you do not have the same number of transactions occurring and the same amount of randomness.

A couple months ago, the biggest news in the ethereum network was this thing called crypto-kitties, which were basically just pictures of cats that people were trading for a lot of money. At one point, something like 10% of all the transactions and computational time on the ethereum network was occupied in pictures of cats. [Laughter] With a private blockchain, that becomes less of an issue.

MR. FOLKER: That is exactly right. There is something called a payment channel on the public blockchain that essentially only settles the transaction at the end of a set time period. It is like a bar tab. You can order as much as you want, but you have to pay at the end of the night and, therefore, you can have transactions — thousands of them — as long as you settle at the end of the time period.

Private or commissioned blockchains by utilities and other energy players have big potential / continued page 42

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The contractor then sold the rooftop systems and assigned the power contracts to Donald and Sheila Golan in January 2011 for $300,000.

The Golans claimed 30% investment tax credits and a 100% depreciation bonus on the systems in 2011. (A 100% depreciation bonus means the full depreciation was claimed in 2011.)

The IRS disallowed the tax benefits, but cited the wrong tax code sections in its notice of disallowance. The case landed in the US Tax Court. Taxpayers usually have the burden of proof to show the IRS is wrong. However, in this case, the burden shifted to the IRS because it was considered to be making a new argument in court.

The IRS argued the solar equipment was already in service before it was sold to the Golans. An investment tax credit can only be claimed on new equipment. The court said the systems did not appear to have been connected to the grid until after the sale.

The Golans never actually paid $300,000. They agreed to pay $90,000 down, but ended up paying only $80,000 of the amount, and not until 2012 and 2013.

As for the rest, they claimed an offset against the purchase price for $57,750 in utility rebates that the local utilities paid the electricity customers and that the customers assigned to the contractor who did the installation, and they gave the contractor a note for $152,200 to cover the remaining purchase price. The note had a maturity date in 40 years and bore 2% annual interest, but did not provide for any fixed payments. Instead, the Golans were required to pay all revenue generated by the solar equipment toward the note balance until the note was paid off. After a default, the contactor was supposed to foreclose first on the solar equipment, but could then go after the Golans for any shortfall.

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because they are not beholden to the computer power of the public internet, but can be run by the utilities themselves. You can have much greater transaction speed.

MR. POLLAK: The processing power required just to power the bitcoin blockchain today is equal to all the energy consumption in Switzerland. We are still in the early stages of blockchain, and that is only bitcoin.

What is the plan to expand without overwhelming our current electricity supply?

MR. FOLKER: You are right. The bitcoin blockchain uses a large amount of energy because its consensus mechanism is based on mining. Computer power is needed to secure that blockchain. There are other ways to create a consensus mechanism.

The Energy Web Foundation's consensus mechanism is proof of authority where every transaction is signed off by an affiliate: PG&E, Shell, Centrica. That does not require mining. The electricity usage by that blockchain is minimal compared to the bitcoin blockchain. There are different types of consensus mechanisms.

MR. POLLAK: So you don't see an exponential growth of energy consumption as blockchain is more widely adopted?

MR. SACK: Maybe step number one, if you are an energy blockchain developer, is do not use bitcoin. It is extremely computationally-intensive and does not have the capacity to manage smart contracts. That is why the ethereum development was so valuable. There are more and more protocols being developed every week.

Bitcoin is a form of currency to buy and sell goods in the market. The energy intensity is likely to be reduced over time as technology evolves. Whether it is proof of work, proof of stake, proof of authority, different conventions are adopted because clearly the trajectory we are on right now is not sustainable.

Security

MR. POLLAK: Michael Horwitz, what do you see as the key privacy and security issues when using distributed ledger technology?

MR. HORWITZ: Most large corporations that are already in transaction systems today, like banks, that may adopt blockchain for various applications are already familiar with how to deal with data and cyber security.

Various breaches have made the newspapers in the last couple of years, but I am more enthused about the distribution of information using blockchain than I am with the information sitting in a data center in the middle of Kentucky for Target, for instance.

You satisfy a lot of security questions just by implementing the technology, especially ethereum and its protocol. It puts users in a more secure position than the traditional ways we have tried to protect data on the internet.

MR. POLLAK: How can that be if everything is being transacted without oversight through smart contracts? Kit Harrison, what type of risks does use of blockchain impose on the utility grid?

MR. HARRISON: I would not say that these contracts are being conducted without oversight.

Information moving from point A to point B is still subject to being intercepted regardless of whether it moves on a blockchain or by other means.

One of the great aspects about blockchain — at least the public ones — is that they are accessible to the public. You can get all the information off them as it is right now. The distributed ledger helps deal mainly with transaction security. You have a digital currency you can use. The real benefit is to be able to transact digitally in a very secure manner.

MR. SACK: I think it is important to differentiate between data security and data privacy.

You will be able to hack into, if it is a private blockchain, or access openly, if it is a public blockchain, all of the transaction data files, but you will not have any idea what the hell they say. They are all encoded, highly encrypted and basically scrambled so that the resource it would take to decode that information is better used on just mining bitcoin legitimately. You will make more money. [Laughter]

MR. POLLAK: Is the real benefit of this technology that standardized transactions can be done millions and millions of times a day or is there some place where more bespoke transactions are appropriately done on this platform?

MR. FOLKER: If you want to have a grid that is more than 20% or 30% renewable — fully decentralized with five million electric vehicles, for instance, in California — then you need to have some way to coordinate that. Marketplaces do a good job at it, but you still need to be able to transact at intervals that are small and at a fraction of cents in cost.

Cryptocurrencies are like finding your neighbors are trading turds, and you don't want to be left out of the action.

If you standardize the contracts, then you have a platform that can be run cheaply. You can add the bespoke private blockchains — they have their function — but if you want to have a world where all these resources are trading, that needs to be standardized.

MR. POLLAK: Going back to Michael Horwitz again, are utilities already implementing blockchain and, if so, for what purposes?

MR. HORWITZ: TEPCO, a very large Japanese utility, has lost three million customers due to deregulation. It created a new entity that allows customers to be able to have access to energy from various resources. The energy need not come from TEPCO. This is a use of blockchain to keep some link to customers that are no longer interested in being traditional utility ratepayers.

Breaking Things

MR. SACK: We come at this more from the operating side, but we are fundamentally venture capital investors. My partner managed the world's most remote power generation and storage asset on the international space station, so if you want to talk about grid security and transmission challenges, that is a tricky one.

We meet with individuals like those in the room and say, "Here is a blockchain concept, a smart contract, a distributed ledger opportunity. Here is the value proposition the company is putting forward. How would this solve an immediate use case for you? How would this have commercial value for you?"

We have met with several dozen energy blockchain startups over the last 18 months. Kit Harrison and Thomas Folker are leaders in their fields. It is important to acknowledge that it is very early, so if you are looking for an immediate multimillion dollar savings from adopting blockchain today, you will be disappointed. But if you do not spend / continued page 44

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The court said that since none of the down payment was paid in 2011, it could not be used to calculate tax benefits in 2011. It said the $57,750 in utility rebates was never paid by the Golans to the contractor. If they had done so, they would have had to have reported the rebates as income first.

However, it let the note for $152,200 be counted as a 2011 payment because the Golans had effectively personally guaranteed payment.

As for the passive loss rules, the Golans said in court that they spent more than 100 hours during 2011 on "the solar energy venture." That was enough, the court said, for the Golans to show "material participation" in the business as long as no other individual involved with it, including contactors, spent more time. The IRS offered no data.

The case is *Golan v. Commissioner*. The Tax Court released its decision in June.

AMERICAN INDIANS are not subject to US income taxes on gravel mined on the reservation, a federal district court said in late July.

The decision is at odds with the holding in the same case by the US Tax Court in March. The district court was dealing with income earned in 2010. The Tax Court looked at whether income had to be reported in 2008 and 2009.

A US appeals court will have to sort out the conflict if the case is appealed.

Alicia Perkins, a Seneca Indian, got permission from the tribe to mine gravel on a Seneca reservation in upstate New York. She owned a trucking company. The company had income from gravel sales in 2008, 2009 and 2010.

She argued that two treaties that the US government signed with the Seneca Indians in 1794 and 1842 bar the US from taxing income that a member of the tribe earns from gravel sales.

The Tax Court concluded that neither treaty spares her / continued page 45

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time working today on proof of concepts and pilots and use cases when many of your competitors are, then that may prove a long-term disadvantage.

MR. POLLAK: We have seen a number of companies use initial coin offerings to raise funding. How do these new funding methods affect the cost of capital?

MR. SACK: There is a token economy emerging now, and it is changing almost week to week. Just yesterday, the chairman of the Securities and Exchange Committee said pretty assertively that he has not seen a single ICO that he would not classify as a security.

Something like 10% of all transactions recently on the ethereum network were crypto-kitty trades of cat pictures for money.

The most important issue for utilities that are working with blockchain companies is to make sure to be careful around the management of regulatory risk. You do not want your supplier to end up in jail and not be able to take your phone calls when the network goes down.

Make sure, if the blockchain company is issuing a token that is a security, that it files a Form D and is only raising capital from accredited investors. The cost of capital is probably going to end up converging toward the cost of equity.

If you are working in different jurisdictions, there are places around the world that impose less scrutiny. Then there are companies that are raising $50+ million in ICOs that are basically getting free money from the cartoon cat market. [Laughter]

This is frustrating to legitimate operators because these companies are then using the proceeds in many cases to hire the best developers and, in Silicon Valley terms, to move fast and break things and professionalize after the fact. This is the challenge for the entrepreneurs in the community.

MR. HORWITZ: Watch the way that currencies have been trading. There has been considerable volatility in how the big cryptocurrencies have been trading this year, but the volatility has shrunk dramatically. That is a signal to me that the market is sensing a firmer regulatory environment around crypto, which ultimately will benefit everything about blockchain.

MR. HARRISON: Watching other people moving fast and breaking things is really frustrating because they often lack even a half-baked business plan. They have a pie-in-the-sky vision that does not meet any sort of logical muster. It is frustrating to be in the same sector and have to go through a normal funding.

We are trying to go to a series A right now, and we see others say, "Oh, we're doing an ICO," and suddenly they have $20 to $30 million in the bank. Meanwhile, we are going through all the hoops and talking to lawyers, and everything is moving incredibly slowly.

My advice for anyone dealing with this is to go slowly. It is more a matter of luck than business acumen when you are dealing with people who go straight to an ICO. When you hear anyone say, "I invested in so-and-so company and it went up 500%," that person won the lottery. That is really all that happened.

Audience

MR. POLLAK: Let's open it to audience questions.

MR. MARTIN: Ernst Sack, you said many utilities already have blockchain study groups. Michael Horowitz, you mentioned this as well. What should the CEO of an independent generator be doing today to prepare for blockchain?

MR. SACK: Spend 30 to 60 minutes on Reddit before you go to sleep every night? There is a lot of value you can get just by paying attention to this community. It does not require budgeting large projects or making investments in start-ups, although we of course encourage that. We love having co-investors from inside the industry. Just be better informed and not as cynical as the headlines may sometimes make you think you should be.

MR. AMSTER-OLSZEWSKI: David Amster-Olszewski, CEO of SunShare. We are a community solar company. We connect directly to the grid, but we sell directly to customers where we control the billing and have a direct relationship with the customers. How would we use blockchain technology in our market?

MR. FOLKER: Community solar is a great example of a limitation blockchain can solve or at least make the business model more efficient. We looked, with the Energy Web Foundation, at something called virtual community solar. Not only is the offtaker virtual net metering, but there is also an aggregation of thousands of solar panels with each being assigned its own serial number or identity on blockchain.

You can literally track production per panel to end-customers, and you can associate your virtual community solar clients with specific production as part of your larger congregation of panels.

MR. DESOUSA: Marco DeSousa, chief legal officer of Fotowatio. For those of us who are less technologically inclined, I was wondering if you could give examples of how blockchain will affect in-house law departments.

MR. SACK: Maybe this won't answer your question entirely, but I suspect you will agree with it. I think one of the great elements of hubris in the blockchain community is just to say smart contract and assume that means you do not have to know anything about laws and regulations.

One of the biggest effects is recruiters will be calling you after blockchain companies have raised that series A or ICO money wanting to hire sharp contract attorneys to help translate the commercial agreements into code. Coders alone will be insufficient. A lot of these startups are in for a rude awakening.

MR. HARRISON: I fully agree with that. The lawyers are going to have to expand the knowledge base a little when it comes to understanding code, which is kind of a daunting task, but it will be important to bridge the gap between the computational side of the smart contract and what appears in the PDF.

MR. MARTIN: I think we just heard we all need to start speaking JavaScript at home to our spouses so we can get up to speed. [Laughter]

MR. SACK: Just remember that when the robots take over, and they will, you want them to see you as a friend who kinda helped them along. [Laughter] ◎

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from having to pay income taxes on the gravel sales. The district court said both treaties protect her from having to pay taxes on the income.

American Indians have been considered US citizens since 1924. The US tax code says that "every individual" is taxed on "all income from whatever source derived" unless the income is specifically excluded. American Indians are subject to US income taxes like everyone else.

However, the tribes are still considered sovereign nations.

Treaties with Indian tribes are interpreted liberally by the US courts. Courts act based on what they believe the tribe understood was the agreement when it signed the treaty.

The 1794 treaty with the Senecas promised that the government will not disturb "the free use and enjoyment" by the Senecas of their land. The 1842 treaty bars the government from taxing "real property" belonging to the tribe.

The Tax Court said gravel is no longer "real property" after it has been removed from the ground.

The district court looked at analogous situations where courts have said there was a strong enough connection between income and land for the US government not to be able to tax the tribe. It said gravel is not a retail product, like cigarettes or gasoline, that is brought on to the reservation, or a commercial improvement on land like an apartment complex. Gravel is a type of mineral that was extracted directly from land belonging to the Seneca Nation.

The case landed in both courts because Ms. Perkins paid the 2010 taxes and sued for a refund in the federal district court. She challenged the taxes the IRS said she owed in 2008 and 2009 in the US Tax Court where taxes do not have to be paid before going to court.

The district court case is *Perkins v. United States*. Tax Court case is *Alice and Frederick Perkins v. Commissioner*. */ continued page 47*

Solar Construction-Start Guidelines

by Keith Martin, in Washington

Solar developers got long-awaited guidance from the Internal Revenue Service in late June about what must be done on future projects to be considered under construction in time to qualify for federal tax credits.

The IRS said, as expected, that the same general principles that apply to wind farms will also apply to solar.

The guidance also applies to fuel cells, small cogeneration facilities (called CHP projects), geothermal heat pumps and wind farms using small turbines of 100 kilowatts or less.

It is in Notice 2018-59.

Solar projects qualify for a 30% investment tax credit, but only if under construction by December 2019.

The tax credit drops to 26% for projects that start construction in 2020 and 22% for projects that start construction in 2021.

The other types of projects to which the guidance applies face varying deadlines.

There are two ways to start construction. One is by starting "physical work of a significant nature" at the project site or on equipment for the project at a factory. The other is by "incurring" at least 5% of the total project cost. With one exception, it is not enough merely to spend money. Costs are not considered incurred until equipment or services are delivered. The exception is a payment counts if the equipment or services are delivered within 3 1/2 months after payment.

The developer must also be able to prove continuous work on the project after the year in which construction starts, but not if the project is completed within four years.

Physical work

Physical work at a factory or by a construction contractor at the site must not start until a binding contract is in place to have the work done.

The IRS said it focuses on the nature of the work and not the quantity or cost. It said "there is no fixed minimum amount of work or monetary or percentage threshold required."

It gave a list of examples of types of physical work it considers significant.

For solar, installation of "racks or other structures" to which solar panels will be affixed at the site is significant. Manufacture at a factory of "components, mounting equipment, support structures such as racks and rails, inverters, transformers" and "other power conditioning equipment" qualifies. Work at a factory on components does not count if the components are a type that the manufacturer normally keeps in inventory.

For fuel cell projects, installation of a fuel cell stack assembly is significant.

For geothermal, installation of "piping," flash tanks or heat exchangers is enough.

Preliminary activity, such as clearing a site or removing existing equipment, does not count.

The physical work must be on equipment that is "integral" to generating electricity.

The IRS said fences are not integral to generating electricity. Roads are integral, but only if they are needed to operate and maintain the power project. Roads that are primarily for access to the site or that are used primarily for employee or visitor vehicles are not integral. Buildings are not integral, but not all structures are considered buildings. For example, a structure that is basically a shell that will be removed when the equipment it houses is removed is considered part of the equipment.

Solar developers must start construction of remaining projects by December 2019 to qualify for full tax credits.

5% test

The alternative is to "incur" at least 5% of the total project cost before the deadline.

Costs are usually "incurred" when equipment or services are delivered. However, a bare payment counts if the equipment or services are delivered within 3 1/2 months after the payment. Delivery can be at the factory. The equipment should not have to go back to the factory for further assembly. It should be integral to generating electricity.

Services count only at the point where all the services that the developer contracted to have done have been delivered.

The 3 1/2-month rule is a "method of accounting." Some developers may be unable to use it.

In cases where equipment, like a fence, is not integral to generating electricity, then its cost does not count toward the 5% test, but it is also ignored when adding up the total cost of the project.

Most developers try to incur at least 7% of the project cost in order to provide a safety margin in case there are cost overruns. The IRS said the developer will be out of luck if the costs incurred before the construction-start deadline end up being less than 5% of the final cost, unless the project can be broken into separate phases or units that can operate independently of each other. In that case, the developer can draw a circle that is 20 times the costs incurred before the construction deadline to see how many of the phases or units can fit inside. For example, suppose a project consists of five separate units, each of which costs \$100X, cost overruns push the per-unit cost to \$120X, and the developer incurred \$25X before the deadline. Twenty times \$25X is \$500X. The final project cost is \$600X. Four of the five units can be treated as under construction in time as the final cost of four units was \$480X.

Continuous work

It is not enough to have started construction in time. There must also be continuous work on the project after the year in which construction started.

The IRS said it will not make developers prove continuous work on projects that are completed within four years.

If work on the project runs past four years, then the type of proof required depends on how construction started. Developers who relied on physical work to start construction must prove "continuous construction," meaning continuous physical work. Developers who relied on the 5% test need only prove "continuous efforts," which can involve steady work on developer-type tasks and arranging financing.

Breaks in continuous work for reasons that are outside the control of the developer are excused. Examples are severe weather conditions, natural disasters, delays in obtaining permits and interconnection-related delays. However, they do not extend the four years. They merely */ continued page 48*

IN OTHER NEWS

The district court said a trial will be needed to establish the share of Ms. Perkins' income in 2010 that was attributable to gravel sales.

—contributed by Keith Martin in Washington

Start Construction

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excuse failure to have worked continuously if proof must be provided because the project takes longer than four years to complete.

The US tax code requires any solar or fuel cell project on which a 30%, 26% or 22% tax credit will be claimed to be in service by the end of 2023. Thus, the continuous work requirement is relevant only for projects on which construction started before 2019. It is a good idea to keep weekly logs showing what was done on projects that qualify under the 5% test and start construction in 2018 in case proof of continuous work will be required. (For other tips, see "Another Rush to Start Construction: Practical Advice" in the February 2016 *NewsWire*.)

Other

The IRS will not issue private letter rulings confirming that projects were under construction in time.

The IRS said that a developer who starts work in one year under the physical work test will not be able to buy more time to complete the project by restarting in a later year under the 5% test. However, this only applies to projects on which construction first starts after 2018. Thus, a project on which construction started in 2018 or before can restart later under the 5% test to buy more time.

Repowering of older projects may allow a developer to qualify for a tax credit on the repowered facility. The developer would have to spend enough on the repowering that the developer is considered to have built a new facility. This happens if the amount spent on improvements is at least four times the value of the used equipment retained from the old facility. The IRS said it will apply this "80-20 test" to each separate unit. Thus, one unit might be considered to have been so extensively rebuilt as to be considered brand new while other units at the same project do not qualify. Construction work on the repowering would have to start before the construction-start deadline. ◎

The Cloud Over Future PJM Capacity Auctions

by Robert Shapiro, in Washington

In what many commentators have seen as a rush to craft a solution in search of a problem, PJM proposed and the Federal Energy Regulatory Commission rejected a plan to change the way PJM runs auctions to buy capacity.

FERC directed PJM to create a different plan altogether.

PJM operates the utility grid in the mid-Atlantic states and as far west as parts of Illinois and Michigan.

Two Democratic commissioners warned that the FERC action could adversely affect the legitimate authority of states to do generation resource planning, such as through state renewable portfolio standards that require a certain percentage of electricity to come from renewable energy.

How the Market Works

The annual capacity auction program, known as the base residual auction, requires existing suppliers of capacity, and new generators that want to provide capacity to earn capacity payments, to bid in the auction to supply capacity three years in advance of the year that the capacity would be needed. The year it would be needed is called the "delivery year."

Under the current PJM tariff for capacity, new combined-cycle gas generators not yet participating in the capacity market would have to offer a minimum price to supply capacity in a delivery year. Some gas generators are exempted; bidding is mandatory for others.

The requirement to bid is known as the minimum offer price rule or MOPR.

Existing generators have not been subject to the MOPR to date.

Under the current rules, the MOPR requirement applies only for the first auction. If a new generator's bid clears once in the auction, then in subsequent years it would not be subject to a minimum offer price requirement. Under the current tariff, the MOPR requirement also does not apply to gas projects that meet certain exemption tests or to renewable generators or to anyone offering demand-side reduction. The MOPR also does not apply to existing capacity suppliers. However, the MOPR does apply to state-subsidized new gas-fired generation.

In 2016, Calpine filed a complaint against PJM at FERC claiming that state-subsidized generators, like existing nuclear plants that are getting price support from their states in order to keep operating, are artificially suppressing capacity prices in the market.

In addition, for the last several years PJM has observed that more renewable power plants were being built in the region and participating in the capacity market, and that other potential subsidized projects, like offshore wind projects, and existing nuclear facilities, were likely to bid to supply capacity in the future.

In April 2018, PJM filed with FERC to amend its MOPR rules. It offered two alternatives and asked FERC to choose which one it prefers. PJM took the position that taking no action in response to its filing would not be a viable option because PJM has no way otherwise to address the growing number of bids from state-subsidized suppliers.

PJM has operating capacity well above the amounts required to meet PJM's existing demand plus reserve requirements. The demand for capacity has remained essentially flat in PJM for many years. The current tariff has not prevented new gas capacity from clearing the auction and completing construction, notwithstanding the number of competing bidders who benefit from government subsidies.

Tension between subsidized and unsubsidized generation is spilling over into how PJM runs its capacity auctions.

Despite these current conditions, FERC found that the existing approach was unjust and unreasonable and decided that both of PJM's proposed tariff revisions were unjust and unreasonable, as well. It offered its own tariff revision.

However, FERC showed a lack of confidence in its own holding. It called for a "paper hearing" to assess what it had proposed, asked a series of questions that it would like the participants to address, and invited additional questions that participants might choose to have the commission consider as well. FERC gave the parties 60 days until August 28,2018 to file comments, then 30 days to respond to those comments, and proposed to wrap everything up by the first week of January 2019, in time to be implemented before the next PJM capacity auction in May 2019.

What FERC Proposed

FERC made a "preliminary" proposal to change the existing PJM capacity MOPR rule in two ways.

First, it directed PJM to expand the MOPR to create a replacement minimum offer rate for all existing and new generating plants, regardless of resource type, with few exceptions.

Why does it matter whether all bidders — or just a small class of bidders like new gas-fired generators — are required to offer a minimum price in the capacity auction? Absent the requirement to bid at a minimum price, existing generators and all new price-subsidized renewable generators could offer capacity as "price takers," meaning that each could offer a zero price that is guaranteed to clear the auction and still receive the auction's market clearing price. With FERC's proposal, on the other hand, there is a risk that such generators will have to offer prices at levels that will not clear the auction and, therefore, receive no capacity payments.

FERC fully recognized that its proposal would mean that the MOPR would apply not only to unsubsidized generators, but also subsidized generators. It recognized that by holding subsidized resources to the MOPR standard, some ratepayers may be obligated to pay for capacity twice — "both through the state programs providing out-of-market support and through the capacity market." This could happen if such a generator's bid did not clear in the auction. FERC said the courts have recognized this risk, but that the courts have found the risk is reasonable given that states retain the right to pursue their own generation policy goals.

However, to mitigate the risk of double payment, FERC proposed a second change to the MOPR rule, called the FRR alternative option. This option would allow, on / continued page 50

PJM

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a case-by-case basis, a utility or other load-serving entity with generation receiving out-of-market support to choose to remove that generation from the PJM capacity market along with a commensurate amount of load, for some period of time.

The amount of time any such generation would be removed is open for public comment. This option would continue to allow the generation to remain on the PJM system and participate in the energy and ancillary services markets, even though it has dropped out of the capacity market. Under current PJM rules, a utility or other load-serving entity would have been required to remove its entire load footprint (the so-called fixed resource requirement or FFR) and exit the capacity market entirely before it would be released from bidding in the annual capacity auction. The proposed alternative (FRR alternative) would allow a load-serving entity to remove only the capacity that would benefit from the exclusion.

These proposals would ensure that all generators that participate in the PJM capacity market will have to offer competitive prices.

However, one risk of the FERC approach may be that the capacity market will shrink dramatically, thus reducing competitive markets generally and turning PJM's market into only a residual capacity market, as more and more generators with out-of-market support exit the capacity market altogether. Calpine recently expressed concern about this potential outcome from FERC's proposal.

Open Issues

In setting the proceeding for a paper hearing, FERC asked interested parties to address a number of important open issues. The issues include the following.

First, what should be considered an out-of-market subsidy? PJM had proposed to define them broadly to include any market payments, concessions, rebates or subsidies directly or indirectly from any government entity, or received in any state-sponsored or state-mandated processes, that are connected to construction, development, operation or clearing of the capacity in any capacity auction

But PJM wanted to exclude a laundry list of items from the definition. It wanted to exclude subsidies that promote general industrial development in an area. It would also exclude subsidies that encourage a power plant to be put in one county or locality rather than another one. Federal tax credits and other tax benefits that are available to eligible generators regardless of location would also be ignored.

Second, FERC asked for advice on what categories of generators should be exempted from bidding under the MOPR.

Third, it asked whether federal sources of out-of-market support should be addressed by the commission action.

Fourth, it asked how long generation receiving out of-market support for which a load-serving entity has chosen the case-by-case FRR alternative should be required to remain outside of the auction.

In the meantime, FERC has established that the proposed MOPR revisions will be effective retroactively to when Calpine filed its complaint in 2016. This could require refunds to be paid to some generators. The significance of the refund requirement is unclear, as FERC did not specify what rate would be used to make refunds.

Recognizing that the timing is tight for a final order before the next PJM auction, FERC offered PJM the option of coming back to FERC to ask for a delay in the 2019 auction until later in the year.

It is unclear whether FERC would permit PJM to seek a waiver to keep the current tariff in place for the 2019 auction until FERC is able to sort things out.

To add to the uncertainty, promptly upon the issuance of the FERC order, Commissioner Robert Powelson announced he will resign in August, leaving the commission with only four commissioners and a possible deadlock of 2-2 in reaching a final order. Commissioner Powelson was part of the 3-2 majority that issued the opinion, with the two Democratic commissioners vigorously dissenting.

In her dissenting opinion, Commissioner Cheryl LeFleur agreed that the PJM capacity repricing proposals should be rejected, but would have been willing to work with PJM's alternative proposal, called MOPR-EX, with some modification to protect resources under state RPS programs, or have PJM consider the new construct approved by FERC in March 2018 for ISO-NE's modification to its MOPR for its capacity market, known as "Competitive Auctions with Sponsored Policy Resources," or CASPR.

Under CASPR, ISO-NE proposed to maintain its current MOPR that applied only to new resources and exempted up to 200 megawatts of renewable energy each auction year.

Then ISO-NE would conduct a second-stage or substitution auction. The capacity price to be paid to all cleared bids would be determined by the first auction. But in the second, substitution auction, existing generators that made successful bids to supply capacity in the first auction will be permitted to offer to retire their capacity in the second substitution auction at a certain price.

Any state-sponsored resources whose bids did not clear in the first auction would be allowed to bid in the substitute auction to acquire the capacity from those existing resources that offer to retire their capacity in the substitute auction. This is expected to allow retiring existing capacity to receive a somewhat lower than capacity-clearing price to exit the capacity market permanently and also allow new state-supported generators to obtain rights to supply capacity at the market clearing price.

Commissioner Richard Glick's opposition to the FERC majority decision was more fundamental. He argued that the FERC order stepped on the state's exclusive authority over electric generating facilities. In his view, the record did not support the finding that there is a resource inadequacy problem in PJM or that the capacity market is otherwise unjust, unreasonable, unduly discriminatory or preferential.

What Happens Next

PJM has been evaluating ways to maintain reliability and improve competitive markets for the last several years. It has also been working diligently to comply with FERC's directive, following its rejection of a Trump administration proposal to force PJM and other regional organizations to favor coal and nuclear plants, to determine the best approach to maintain resilience of its vast interconnected system.

PJM is the largest and most mature regional power market, with about 185,000 megawatts of installed capacity spread over 13 Mid-Atlantic and Midwestern states and the District of Columbia.

Pressure from the Trump administration to do something, for what clearly appears to be political rather than reliability reasons, seems to have caused PJM to rush to judgment with a half-baked proposal, and to cause FERC to rush to decide the matter with another half-baked alternative.

It remains to be seen whether, after all of the FERC deliberations are completed and the final decision lands in the court of appeals, the appeals court will decide that FERC lacked authority to modify the existing MOPR procedure as suggested by one of the Democratic commissioners, Richard Glick. The commission cannot modify the existing tariff unless that tariff was unjust and unreasonable. This was the result of a court's decision in 2017 on review of FERC's previous attempt to modify the PJM tariff when PJM made a filing to FERC to modify its capacity tariff in a different manner.

All of this PJM action is being played out at a time when PJM and FERC were hearing the sounds from the constant drumbeat from the White House and the US Department of Energy to take action to keep uneconomic coal and nuclear plants operating, claiming an emergency that PJM and every other regional transmission organization said does not exist in reality. In other words, the federal executive branch is pushing hard for federal subsidies that would clearly suppress prices of competing gas generation and other technologies, like renewable power and energy storage, that utilities, state commissions and the general public support for both economic and environmental reasons.

FERC has recognized that its solution needs work, calling it "preliminary" and seeking comments on a number of highly important issues that should have been thoroughly evaluated before issuing any directive.

It may be that FERC will be able to absorb all of the comments received and produce a better product and market structure that nimbly adjusts to the rapidly changing power resources that the country seems to be demanding despite federal executive opposition.

However, there is also a significant risk that a poorly redesigned market structure will undermine an extremely successful competitive market system and cause renewable power to become less viable over time following the expiration of federal tax credits and possible removal of their resources from the capacity markets. In any event, whatever final order emerges from this proceeding will be challenged in court, causing additional uncertainty for future PJM annual capacity auctions. ◎

Energy Storage Gains Ground

How quickly and how much will energy storage transform the power sector? Four prime movers in the push to install batteries talked about where installation of batteries already makes economic sense and what is driving current adoption at the 29th annual global energy and finance conference in June. The panelists are Tom Buttgenbach, president of 8minutenergy Renewables, John Carrington, CEO of Stem, Ed Fenster, executive chairman of Sunrun, and John Zahurancik, former CEO of AES Storage and now COO of Fluence, a storage joint venture between AES and Siemens. The moderator is Caileen Kateri Gamache with Norton Rose Fulbright in Washington.

Utility-Scale Storage

MS. GAMACHE: John Zahurancik, what is the business case for grid-scale storage?

MR. ZAHURANCIK: There are a few different business cases.

One problem we have in the storage business is storage brings a lot of benefits to the market, but they are not priced into electricity.

When storage is added to a system, in every case we have seen, it has lowered the cost of that system. We have a very fast responding technology. It is always connected and always on. No dispatch decision has to be made as to whether it is there. It does not have a minimum heat rate. It can stay on for five seconds and turn off for the next hour. It can be back on again for an hour and turn off for five seconds.

It can absorb power when the grid is in a period of over generation, and it does not matter whether the over generation lasts for one minute or two hours. Storage can be used economically to improve how everything else on the system is dispatched.

It is difficult to quantify the benefit from that kind of system optimization against upfront dollars per megawatt, which is what the industry has become accustomed to using for comparisons, or in terms of dollars per megawatt hour, which is the principal metric in the renewables space.

The key challenge for policymakers and electricity purchasers is how to do the math to compare alternatives.

Fortunately, in a lot of places in the world, people are starting to do the math the right way. Storage is finding a place in the market today mainly in support of things like grid stability, frequency regulation, very fast acting ancillary services. Those markets are usually where storage proves itself.

It started that way in the United States. We did the first project like that in 2007 and 2008. In almost every other market in the world, that is also where storage has started.

It then moves into things like peaking, where storage can avoid the need to build costly additional generating capacity that will be available sporadically for a few hours at a time, and then it moves into deferring the need to build costly additional transmission and distribution lines. We can put storage in places where it is nearly impossible to site other resources.

The bottom line is there are a few different business cases, and we see storage popping up all over the world in places to solve constraints, congestion and pricing issues.

MS. GAMACHE: Tom Buttgenbach, why does it make sense for a utility-scale solar developer like 8minutenergy Renewable to make part of its business model developing storage projects?

MR. BUTTGENBACH: Renewables, and particularly solar, are on the way to becoming the cheapest form of electricity generation. Power prices are declining 10% to 15% every year, and that trend will continue.

However, being intermittent as a resource, solar cannot power the country unless storage is added to it. We see storage as a necessary component of a renewable power plant.

Solar has a huge advantage over wind simply because you may have two weeks with no wind and it is hard to design a system around a generator whose output is that hard to predict. Solar even on cloudy days is predictable, and so you can operate a grid with solar plus storage. We believe that a large portion of the US power generation feed over the next couple decades is going to transition to solar plus storage. Storage is a must-have in terms of the transition to renewables.

Distributed Storage

MS. GAMACHE: Ed Fenster and John Carrington, what is the business case for deploying storage on a distributed basis?

MR. FENSTER: We see three benefits from distributed storage. One is managing the time of day that power is generated and dispatched.

Another benefit is the ability to use such storage facilities to provide backup power, thereby helping the grid with reliability and resiliency. The third benefit is alleviating local grid congestion. It is not uncommon on a summer evening in California to find wholesale power selling for $1,000 a megawatt hour in one place and two counties over for $50.

We are finding that homeowners are willing to pay for increased reliability. There is value in the time-of-day shift and then also from using storage to provide grid services. The latter helps the local utility to defer having to invest in new transmission and distribution lines.

Building new transmission and distribution infrastructure is like tunnel and road building; it is expensive, and it is getting more expensive. It is competing against solar panels and batteries, which are two technologies that are becoming less and less expensive.

The cost lines will cross over time. I don't know how many of you drove over the Tappan Zee bridge to get here, but wouldn't it have been nice not to have had to pay for that?

We think storage will eventually be everywhere. It will be what enables really high penetrations of renewables. There are a couple of problems that really only distributed storage can solve, and we are excited to be doing that.

If you ask homeowners why they go solar in the first place, freedom and independence from state-sponsored monopolies are at the top of the list. There are a lot of well-run utilities, but there are not a lot of loved utilities. There is a reason why the creators of The Simpsons had Mr. Burns own a utility.

All of our new solar installations in Hawaii now have storage. We first launched storage in southern California a few quarters ago. We said in our last earnings call that we have more than a 50% take rate in southern California. Our take rate is 20% across California as a whole, up from 15.25% the quarter before, 10.25% the quarter before that and 5.25% before that. We hit 10% in the first quarter this year in Massachusetts. People want it, it is happening, and it is really exciting.

MR. CARRINGTON: For commercial and industrial customers, the use cases are remarkable. The Rocky Mountain Institute has a wheel showing 13 potential value streams that behind-the-meter storage can tap into.

They cannot all be monetized in every market, but a storage device that is being used solely for peak demand reduction, which is the most common use in California today, is effectively an iPhone that is being used as a telephone only. We look to drop as many apps into that storage device to help monetize all of the potential value streams that are available to storage.

C&I customers are looking for savings on their demand charges. They are doing energy efficiency plays. There is a big 15-minute peak every month that accounts for over half the electricity charge on their bills. They want something to avoid the peak charges without having to alter their business operations. We provide an answer.

We also give them the opportunity in places like California to participate in the wholesale market. We had more than 600 calls last year to help our customers participate in wholesale markets, both real-time and day-ahead. Storage is the fastest responding product that you can put into a building.

Our storage customers are also able to participate in a Southern California Edison contract that we have for 85 megawatts of storage capacity. A lot of utilities are starting to embrace similar arrangements.

So C&I customers can use storage for peak reduction and to participate in grid services. Chief sustainability officers and energy buyers at Fortune 500 companies want to be able to do that.

Meanwhile, the electric utilities look at this as an opportunity to have capacity very quickly, frequency regulation and a lot of other things that can be provided by storage.

Both commercial and industrial companies and the utilities are potential customers for us. The opportunities vary by market. Massachusetts is different than California. We are in Ontario. We are in Japan. We are in multiple states in the US. The uses vary by location, but the beauty of storage is the simplicity and the elegance is when you put the right software platform on top to enable these businesses and utilities to maximize value.

MR. BUTTGENBACH: Talking about Mr. Burns, I think he is a control freak, and I am not sure he is willing to empower his customers. That is probably something we see in the utility space as well.

Location Matters

MS. GAMACHE: The value of storage varies by geographic location. Fluence, for example, is in 17 countries. Where in the US is it finding the greatest traction and why? In which other countries and why?

MR. FENSTER: It is different in the distributed storage business because of reliability and resiliency. We had the good fortune of launching in Florida and Texas two weeks before the hurricanes last fall. Those markets ramped very quickly after the hurricanes. The number one question people ask is, "How far above the ground do you put the battery?"

Markets with lower reliability drive a lot of demand on the distributed side. Markets, like New York / continued page 54

Storage

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and California, that have congestion issues are also fertile ground.

Wherever you see high population density, power is expensive because building more generating capacity and power lines is expensive. Another good market for storage is where you start to see lower mid-day wholesale power prices relative to evening power.

MS. GAMACHE: I was at a conference last fall where an industry specialist said it is not a question of whether a huge reliability incident will occur in California, but rather when it will occur. Do you think storage will circumvent that?

MR. FENSTER: Absolutely. The California utilities have said that given state liability statutes and high summer winds, they are going to start proactively turning the grid off to avoid fires.

People obviously will want to buy batteries in such a market. That is already the case actually. The United States has the least reliable power in the OECD. There are more power outages here than in any other developed nation, and the number of such outages is increasing.

Those of you in the room who are from the New York City area probably know people who have been without power in three of the last 120 weeks. There is real demand to solve those issues.

MR. CARRINGTON: Hawaii, California, Massachusetts, Arizona, Texas and New York are the immediate growth states for us. The issue with New York, at least in the Manhattan area, is the New York fire chief does not want to burn his buildings down, and this will probably come as a huge surprise, but the LA fire chief does not want building fires in Los Angeles, either. We are working through a lot of policy and trying to get people comfortable with lithium ion batteries in buildings.

The power grid is constrained. Add a few Teslas in a parking garage underneath a building, and the problem gets worse.

Getting past the policy hurdle on which the fire departments are focused would open up tremendous capacity in urban markets like New York and Los Angeles.

MR. ZAHURANCIK: We see good markets in a variety of places. California has been very active for a long time. We put the largest battery system in the US into San Diego last year. We are building a 100-megawatt, 400-megawatt-hour facility for Southern California Edison that will replace peaking capacity there. That type of project is moving to larger and larger scale and is starting to require traditional project financing to be built.

We see other places like the Dominican Republic where we are putting in storage as a way to displace expensive diesel backup systems that were being used to maintain a fragile grid. The path the hurricanes took last year is a path of opportunity for storage. The storage systems being installed along that path are some of the most stable units the Caribbean islands have. They allow some thermal units to be taken off line during big storms, but still maintain the grid.

Sunrun already has a 20% take rate for batteries with rooftop solar systems in California, up from 5.25% a year ago.

I don't know what to say about New York. I love New York. We did one of the earliest storage projects in New York in 2009. We eventually relocated one such project to the advanced state of Ohio because New York was not quite as advanced as we thought.

I put New York in the same category as Brazil. It is the Brazil of the US. It is very large. You can't ignore it. It has great promise in the future, and we keep hoping the future will come someday.

Good Markets

MR. BUTTGENBACH: California is clearly a good market for us because it has a regulatory environment that requires storage. The regulatory environment is everything from the storage requirements for the investor-owned utilities to SB 801, which requires LADWP, the largest municipal utility in the country, to provide 400 megawatt hours of storage.

The regulator is driving storage, but there is also a market need because California has a lot of renewables. California will hit the 33% mark, and possibly even exceed it, by 2020. The state has already adopted a new target of 50% renewables. Storage will be needed to integrate that massive amount of new, mostly solar power generation coming on line. We may even see a 100% renewables target from the next governor. That is on top of local initiatives. For example, the Los Angeles city council asked LADWP basically to be 100% carbon free as a utility within the next 10 years.

There is a lot driving this market. On the other hand, coming back to Mr. Burns, his employees are not necessarily the most educated and advanced thinkers. Everybody here on the panel agrees that storage has a lot of value and can address a lot of problems. The utilities hear about that, but their senior engineers who make the decisions were in engineering school 30 years ago when there was no storage. For them, it is a new technology that is scary by nature because they don't understand it. It is complicated. It is not like a gas plant that you can turn on and off and look at how long it takes to ramp it up and down.

They understand intuitively that there are lots of advantages, but they are very slow to adopt new technologies. We should already be seeing utilities moving to replace gas peakers with storage since doing so already makes sense at today's prices. But the utilities are not doing it because it will take them a few years to study the problem before approaching their regulators to educate them.

You saw the same pattern with smart phones. It took a long time for people to adopt them, but then one day everybody had one. It just took a lot longer than what the experts predicted.

MR. ZAHURANCIK: I think that is partly why we are seeing activity built on activity. Once a utility becomes familiar with storage, it tends to procure one round of storage after another. Once they have educated themselves, they see value in it.

Pretty much universally every independent system operator to whom we have talked gets the value of storage quickly. To have that level of control and management in the system is of obvious benefit. The challenge has been working it through the procurement processes of utilities.

Where it is purely a commercial decision, customers are moving very quickly to make those decisions because they see the benefits from storage.

There is a great deal of interest today in integrating solar with storage. We are focused currently with a number of people on ways to connect at the direct-current level to get additional benefits out of the solar output by retaining electricity that has typically been lost in the past because it is above the interconnection cap. We can now retain that value as well as mold and shape the rest of the solar output. A lot of new things are coming.

MR. FENSTER: There are some rules that need to be reworked first since the existing legal framework never envisioned storage. A good example is Hawaii, where almost all of our installations for some time have had storage. With 40% renewables penetration in Hawaii, the grid cannot function without it.

The batteries store 20 kilowatt hours during the day. They bleed it out at 3 or 4 a.m. That is like having a thoroughbred locked up in the barn. What should happen is HECO should call us at 7 p.m. at the time of peak demand and say, "Please empty all the batteries."

That is still off in the future. The rules and contracts to make better use of storage do not exist yet. We are working closely with the unregulated side of National Grid to propose rules to deal with the complexities of net metering and storage and capacity, and how to put that all together in a scalable way. The fundamental underlying unit economics are already in place.

I am confident that if there will be a constraint in storage, it will be the supply. It is not going to be anything else. We just have to work as an industry to get the right rules in a place so that we can realize the value that exists currently.

MR. CARRINGTON: Let me give you one quick timestamp of 24 hours ago on the utility side. I was at a breakfast yesterday morning at the Edison Electric Institute meeting in San Diego. There were about 25 people, including 12 CEOs of major utilities: Duke, PG&E, Southern, all represented. It was evident to me for the first time, more than at any time in the past, that they are really trying to figure this out.

Storage was a huge discussion. For now, they are laying the challenges off on their regulatory commissions, but I think they also need to become more educated themselves.

Unfortunately, the domain expertise level on energy at many of the commissions is a little low. We are working on education. I was 16 years at General Electric. I do not have the policy team that I had then behind me now, so it is a long, arduous process, where you have to get everybody in the industry around this.

I am bullish, especially coming out of the breakfast yesterday. The utilities seem more interested and */ continued page 56*

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more willing to push this than they were at the same event last year.

Barriers

MS. GAMACHE: The Federal Energy Regulatory Commission issued Order 841 in February to require all regional transmission operators to allow energy storage to participate in every market in which it is capable of participating. The order also eliminated some other perceived barriers to storage. Will it be a game changer by allowing storage owners to tap into more potential revenue streams or are we already there?

MR. ZAHURANCIK: The order was helpful. It is probably not a game changer. We are already seeing the game change because the basic economics of storage are improving.

We are seeing spinning reserves disappear in a lot of places. They have to be replaced with something. Flexibility and grid resilience have become a common theme. They are what storage really speaks to.

We have to continue to get the policy environment in line so that it does not become a barrier. It is an inadvertent barrier because no one expected to have a technology like this when the current rules were written. The more we can do to put things on a level playing field, the faster storage will advance.

Three or four years ago when Keith Martin invited me to participate in a similar storage discussion, lithium ion batteries had already emerged as the favored technology. Things have been scaling up. Factories are being built at larger scale all over the world. The challenge has been getting the kinds of suppliers that can stand behind guarantees over the long term.

MS. GAMACHE: Why is all the attention on lithium ion rather than other technologies?

MR. CARRINGTON: The strong demand for lithium ion in the transportation sector is driving it down the cost curve. The power industry is a beneficiary of what is happening in that sector.

You need to add cobalt today to lithium ion for transportation because it improves energy density. Batteries that do not have cobalt actually do better for stationary storage, but only a few manufacturers make such batteries. They are a little bigger and weigh a little more, but they last longer, dispatch faster and are less likely to catch fire.

I think we will continue to see innovation, but scale is the key, and while there may be technologies that emerge that are slightly better-suited or might theoretically be lower cost than lithium ion for stationary storage, lithium ion has the advantage because it is reaching scale in transportation.

MR. BUTTGENBACH: It is also important to note that lithium ion batteries can do a lot more than a flow battery, which can do energy shifting, which is valuable, but all of the other services we talked about today — frequency regulation, for example — can only be done cost-effectively with lithium ion batteries.

Audience Questions

MS. GAMACHE: Let's open the floor to audience questions.

MR. STURCKE: Blake Sturcke, COO of Encore Renewable Energy. We are a C&I developer based in Burlington, Vermont. I have two questions. The first is for John Zahurancik. I am curious what percentage of your batteries are being financed today by customers as opposed to by third-party equity investors? The other question for the panel as a whole is what percentage of deployments is being driven by readily quantifiable considerations like return on investment as opposed to other perceived benefits that might be harder to quantify, like reliability?

MR. ZAHURANCIK: Let me take the second question first. Everything we have ever sold to a customer or deployed on behalf of someone has been justified on economic terms. We have not seen a big market for feel-good projects or maybe we are not very good at winning them.

Fluence is a technology supplier. We sell storage units and help to deploy them. We can do a full turnkey installation or just a system supply. Some customers bring their own financing. Not all do. Some storage systems are being sold to utilities that put them into rate base. In such cases, the financing is at the corporate level rather than specific asset finance.

As we sell more to independent power-type developers, we expect to see more project financing. In some cases, we have done it by packaging the storage with another asset. However it ends up being done, the financiers will require independent engineering reviews, evaluation of the longevity of the technology and so on.

The mix is shifting toward independent storage projects as the projects get larger.

MR HOWES: Walter Howes with Verdigris Capital. I just came back from Asia, and the Chinese seem to be making a major investment in graphene batteries. Entire cities, transportation systems, mobile, stationary, are wrapped around graphene, while they seem to be cornering the lithium supply so we can't have it. What about graphene? The performance of graphene seems to put lithium back in the buggy era.

MR. ZAHURANCIK: We have already seen graphene used in some large-scale projects. We continue to look at it. We are agnostic to the technology we use for the underlying battery cells. As long as the material is highly efficient, has a reasonable life and can ultimately be financed with some guarantees around it, we will continue to evaluate it.

MR. HESSE: Balduin Hesse, CEO of Frontier Renewables. What do you see in large-scale battery storage deployment as the commercial pole mechanism? Is it a PPA? Is it a combination of ancillary services and three or four other revenue sources? What is the commercial mechanism that will drive the mass deployment of large-scale storage?

MR. ZAHURANCIK: It will be a PPA in some cases. It is becoming more common to see all-source RFPs for power, and storage is competing effectively in those.

There is usually some triggering event, like congestion or the inability to put something into a local area. It may be flexibility. Just the speed of response is starting to get valued appropriately, and that tends to move storage to the front.

More New Trends

Four industry veterans talked about new trends in financing renewable energy projects at the 15th annual ACORE/Euromoney REFF-Wall Street conference in New York in late June. The following is an edited transcript. The four are Ted Brandt, CEO of Marathon Capital, David Giordano, managing director of BlackRock Alternative Investors, Susan Nickey, managing director of Hannon Armstrong Sustainable Infrastructure, and Ray Wood, global head of power and renewables for Bank of America Merrill Lynch. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

MR. MARTIN: What new trends do you see in how projects are being financed, and how developers are capitalizing themselves?

MR. GIORDANO: There is a lot of competition for asset-level investments in renewables. Most of the competition is around more mature assets, call them late-stage development through assets that are already in operation.

There is less activity at the higher risk end of the spectrum, meaning earlier stage, and also at the innovation end of the spectrum. This sector needs more creativity and innovation in the siting and permitting stage of projects.

MR. MARTIN: So we need more innovation from financiers and investors at one end of the spectrum. What recent innovations do you see along the rest of the spectrum?

MR. BRANDT: We have seen a lot of innovation around development capital.

MR. MARTIN: What are examples?

MR. BRANDT: Smaller developers have traditionally relied on money from family and friends. But second-round capital is now coming from pretty innovative capital providers that have been looking at early- and mid-stage companies. That is how Cypress Creek Renewables and a whole lot of other folks got traction and grew rapidly.

MR. MARTIN: More details, please.

MR. BRANDT: What we used to see is all development was done with 100% equity and, over the last couple years, equity has become the first leg, but then non-dilutive mezzanine funding — call it 13%, 14%, 15%-type of money — comes in.

MR. MARTIN: And who provides that?

MR. BRANDT: There are a number of / continued page 58

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mezzanine providers. One the most innovative is Scott Brown at New Energy Capital, but at least six or seven other companies have entered the sector.

MR. MARTIN: Is the mezzanine money preferred equity or debt?

MR. WOOD: Both. We have never had this much liquidity in the market. Looking back at the last three to four years, developer profits have been extremely high. Equipment prices have fallen, interest rates have remained low, and there has been a return to a kind of a basic capital structure for projects, after the yield co experiment where equity was cheaper than debt for a short period of time.

The capital stacks still have at their core traditional leverage against an IRR-based equity investor. There are financial players who are comfortable with the asset class and now want to earn higher returns by investing at the development stage. You have strategics who would like to move into development themselves and who might invest in order to learn the business. There are several other players who are also thinking about it.

You have a convergence of appetite for development companies and, to Ted's point, that has spurred innovation in capital structures. The money could come in as preferred equity. It could be mezzanine debt.

There is a sense of optimism. Construction debt is plentiful. Tax equity terms are improving, notwithstanding tax reform. You have strategics interested in investing equity. So what could go wrong? The money is there. We are all here. Let's go party.

Timing

MR. BRANDT: The challenge now is equipment prices are going up due to tariffs. At the same time, electricity prices are low and falling, causing load-serving entities to wonder why they should lock into 20-year power purchase agreements. You have shorter-duration PPAs, if you can get them at all. The last three to four years have been phenomenal, but you have a looming end to federal tax credits for renewables and a rush to build and, with increasing equipment costs, where are the returns?

Michael Polsky said in the session immediately before this panel that if you are not making money from a project during the PPA period, you are not ever going to earn money from it.

The risk is that the returns to which people have been accustomed in the past are collapsing just as everyone shows up for the party.

It is a pretty interesting market right now. There is frenetic activity, but storm clouds are looming.

MR. MARTIN: Ray Wood, when do the financiers lose interest as contracted revenue streams shorten in duration? The reason Michael Polsky said that if you are not earning money during the term of the power contract, you will not earn it later is because there is always someone else who will offer power for less after the project comes off contract.

MR. WOOD: That's a very good question, but one that is hard to answer. It is hard to find a power contract in Texas, and yet projects are being financed based on hedges that run 10 to 12 years. We see some community solar projects with five-year subscription agreements, and those are getting done. Whenever we say doom and gloom and this is not going to work, there is a new wave of capital that makes it happen.

MR. GIORDANO: What people have loaned against or invested equity in has done pretty well. There are only two things that ultimately stop the party. One is if real interest rates continue rise and the other is if the spread between industry returns and real returns narrows to such a degree that investors start losing money.

Short of those two seismic events, the party will continue. I was at a conference — as a matter of fact, your conference, Keith — where Herb Magid of Ares said: "I'm on this global $120 billion asset management platform. I think my business sucks." I'm talking to lots of people, and everybody else says, "Our business sucks, too." Yet the market remains awash in liquidity.

The wall of money is not unique to this business. It is all over the capital markets, both private and public, everywhere.

MR. MARTIN: Susan Nickey, we just heard that the last three to four years have been good for developers. There are possible storm clouds ahead, but there is also optimism. Do you want to add any new trends to what has already been said?

MS. NICKEY: There is innovation in terms of how capital is being put to work in distributed generation. Commercial PACE programs are bringing capital to help real estate owners become more energy efficient or convert to using more clean energy.

Investment funds are looking for ways to decarbonize their portfolios.

Companies that have been major leaders — the Europeans, in particular — are not only continuing to invest in utility-scale renewable energy, but they are also acquiring companies and diversifying to behind the meter on the distributed side.

These are all areas that need more capital and provide room to innovate.

In places like North Carolina, the PPAs now run for 10 years. We are seeing 15-year loans with the last five years of debt service being paid out of merchant electricity sales. That is an innovation that probably can only be explained by the oversupply of bank debt. Banks are not ready to finance purely merchant projects, but things are creeping in that direction.

If you are not making money during the PPA period, you may never earn money from a project.

More Merchant?

MR. MARTIN: Andy Redinger from Key Bank said at a conference a couple of years ago that he has been trying to persuade Key Bank to lend without a power contract. He said, "We lend to McDonald's based on future hamburger sales. There is no contracted revenue stream. Why is power different?" Do you see the market moving in that direction given that PPA tenors are shortening?

MS. NICKEY: The challenges in merchant power deals are basis and congestion risk. You may be able to run sensitivities as an investor around views on gas prices and future electric prices, but how do you forecast around basis and curtailment risk?

MR. GIORDANO: One thing we have been watching is the unbelievable competition across the bank market. For years and years, the constraint with banking always worked out to coverage ratio applied to the contract term. Those coverage ratios are becoming tighter.

MR. MARTIN: "Tighter" meaning instead of 1.35 times debt service for solar, the coverage ratio is what?

MR. GIORDANO: Without insurance, 1:25x and, with insurance, 1.1x.

MR. MARTIN: You are using the word "insurance" to mean a solar production put?

MR. GIORDANO: Right. A number of insurance products are coming to market that guarantee electricity production. Lenders have been using such insurance to justify lending more money against a lower debt service coverage ratio. Debt might move from 42% in a typical capital structure to 52% or 53%. It reduces the amount of expensive equity required in a project.

Pension Funds

MR. MARTIN: Let's drill down into some trends. One new trend is assets moving to pension fund ownership. Are the pension funds only buying operating assets? Do you see them also bidding earlier in the development cycle?

MR. WOOD: We see them buying at notice to proceed with construction. They no longer insist that the project already be in commercial operation. There is little to no difference in the discount rates used to price a project at NTP rather than the end of construction. We have seen some pre-NTP sales as well.

It is not just pension funds that are doing this. It is insurance companies, money managers and strategics, as well. Most people view the construction risk as being relatively easy to accept in cases where the EPC counterparty is creditworthy, unless there is something unusual about the project.

MR. MARTIN: The pension funds seem to be the low cost capital at the moment. Am I correct? If they are the low cost capital, how are others like private equity funds getting traction?

MR. WOOD: Private equity funds are bidding on development platforms and then earning a return through some catalyst like reselling the company after it has had a period of organic growth. I can't think of any situations where a private equity firm, other than a dedicated infrastructure fund, has just bought a contracted portfolio.

MR. BRANDT: I think that's right. Pension funds that three or four years ago were interested only in operating assets have migrated over the last couple years to earlier-stage projects in order to get higher returns.

For example, Omers is buying Leeward. It is a purchase of a development platform that owns both / continued page 60

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a development pipeline and operating assets. We saw AIMCo, together with AES, buy sPower, another development platform. We are hearing more frequently from larger pension funds, particularly Canadians, that they are willing to invest earlier in the development cycle to earn higher returns.

MR. MARTIN: That seems to be another trend — disinvestment in Canada to reinvest in the United States because of the disparity in tax rates. The US rates are now significantly lower.

Coming back to the pension funds, they have a hard time owning solar assets during the first five years when the investment tax credit is vesting or owning wind assets during the first 10 years when production tax credits are being claimed on the electricity output. If you see them invest early, are they investing through blocker corporations?

MR. BRANDT: Every such transaction we have seen has involved a blocker corporation.

MR. MARTIN: Are you seeing any novel structures being used to make such investments?

MR. WOOD: They have been pretty plain vanilla.

MR. BRANDT: I think people generally play it conservatively when it comes to that front. They use a blocker corporation so as not to do anything that could harm the tax benefits at the project level. We are not seeing anything exotic.

Tax Equity

MR. MARTIN: Another trend is the percentage of the capital stack that is tax equity is shrinking as a result of the lower corporate tax rate. What percentage of the capital stack is tax equity today in a solar project versus a wind project?

MR. GIORDANO: It is 30% to 38% for solar, depending on the structure. For wind, it depends on the capacity factor, but we are seeing 47% to about 62%.

MR. MARTIN: Have there been any other effects from the tax reform bill the US enacted in late December besides shrinking the percentage of tax equity in the typical capital stack?

MS. NICKEY: Greg Wetstone [CEO of the American Council on Renewable Energy] reported this morning on a new survey that shows 40% of respondents say it is business as usual and 30% believe the effects of the tax bill are still to be determined, but people are still investing. There are more tax equity investors today than before tax reform.

It took time at the start of the year for everyone to digest what had been done and to redo deal models. A lot of time was lost, and projects were delayed. The outside deadline of December 2020 to finish wind farms is starting to be a concern.

MR. MARTIN: Speaking of that, MAKE, a consultancy, estimates that people stockpiled enough turbines in late 2016 to build 45,000 megawatts of new wind farms and qualify for production tax credits at the full rate. Many people sitting on such equipment are asking how much more time they have in practice to find a home for the equipment.

MR. WOOD: I think the moderator should answer that question. That's a little snarky, but you get those calls, my friend.

MR. MARTIN: You guys are in the market. Paul Gaynor from Longroad Energy said last week at a conference that people are looking at this point where they can deploy most rapidly, and that is probably in ERCOT.

MS. NICKEY: Just what we need.

MR. GIORDANO: I think there are some white knuckles, but I don't think the clock has run out yet.

Import Tariffs

MR. MARTIN: Then let's move to import tariffs. President Trump announced in the last few days that he plans to impose a 25% import tariff on $50 billion a year in Chinese goods. The targeted goods are divided into two lists. There is a $34 billion list on which the tariffs will take effect on July 6. There is a $16 billion list on which the tariffs will take effect later this year. The $16 billion list includes solar panels and cells from China that are already subject to a 30% tariff plus anti-dumping and countervailing duties.

Do you see much effect? Are you seeing many solar panels imported directly from China for use here?

MR. GIORDANO: My sense is that the developers are adapting. We are not seeing much direct sourcing from China.

MR. MARTIN: This is just the latest round of tariffs on top of other tariffs Trump has imposed this year on steel, aluminum, solar panels and solar cells from virtually all countries. We are seeing retaliatory tariffs imposed on US goods by Canada, Mexico, the European Union and China. This makes for uncertainty about what things will cost. What effect is the uncertainty having?

MR. BRANDT: It can't be good, but it is too new really to assess. By the time we see a deal teed up for financing, the solar panels and other equipment have already been secured.

MS. NICKEY: There has been a rush on First Solar panels because they are not affected by the tariffs. There have been some slowdowns because of difficulty getting panels.

MR. GIORDANO: We have not seen the effects work through the system fully yet. The next six to 12 months will tell how they will affect pricing. Over the 15-year history of this conference, we have seen changes affecting all parts of the market, from the offtake side and the capital side, both debt and equity, developer profits, etcetera. The market has rolled with the changes.

MR. MARTIN: The tariffs tend to push up costs. In 2013, there was a drive to reduce the cost of capital. A lot of new concepts were explored, such as yield cos, solar REITs, MLPs, Canadian income trusts, securitizations. Do you see a similar drive starting, perhaps pushed by the import tariffs?

MR. WOOD: The market is awash in liquidity, so access to capital and the cost of capital are not current constraints. The tariffs are probably driving EPC margins and procurement, and there are probably things that can be done at the project level to improve output. That is where the efficiencies are coming.

You had about a 12% or 13% year-over-year decline for the last several years in the cost of solar, and maybe 7% to 8% for wind. So now you have this uptick in equipment prices, and the real debate is where the innovation will come from to offset those costs.

The people winning the PPAs have assumed a certain forward curve and they have been able to procure below that point over the last three or four years; hence the profits. We will see whether there is a stuck generation that gets caught. The jury is still out.

MR. MARTIN: At the Infocast solar finance summit in March, several CEOs said they expect to see some stress later this year for the reason you just said. Solar companies signed contracts to deliver electricity at prices that assumed a continuing downward trend in equipment costs. That downward trend has been arrested by the tariffs. Do you see any evidence of such stress?

MR. WOOD: No.

MR. GIORDANO: I think what we continue to see is different dials being turned to make the projects work, to fit the PPAs that are getting signed, and this will continue. The equipment manufacturers have margin built in. If you compare equipment costs to where they were 15 years ago on a real basis to where they are today, you might argue that there is still room in the current pricing to absorb some of the shock.

You could argue that equity is still being priced 300 to 400 basis points too high compared to the cost of equity in traditional real estate investments. So we are still at an early stage in the transformation of capital for this sector. Returning to a word that has been used several time this morning, innovation, it does not just mean more leverage. Innovation in the industry as a whole looking means through a different lens, reclassifying away from an emerging stage and into mainstream infrastructure.

MR. WOOD: There has been a maturation of the sector. Developers who may be facing cost pressure to deliver electricity at prices promised under new PPAs can now sell a project to a utility that wants to put the project into its rate base. The utility may even buy the project at an early stage when the land has been procured and there is an interconnection agreement.

These sales are early in the permitting process and may not earn the developer as much as if he advanced the project farther, but there is a still a very good profit margin. The developer can then recycle the development capital. If we do have this conundrum where people bid too low to win PPAs, I think you will see utilities filling the void.

Utility stocks are off a little with tax reform and with the yield curve, but certainly not catastrophically so, and they continue to be rewarded for adding to rate base.

MS. NICKEY: We see more and more developers looking at adding energy storage to be able to grab other revenue streams that will help make these projects more economic.

Other Trends

MR. BRANDT: Another trend is we have been pitched now 10 times by people that want to tokenize the cash flows in solar projects. I keep scratching my head and asking, "Do you really think the problem in the business is that it is not efficiently financed?"

There are a lot of people with business plans who think that bringing the cost of equity in C&I and residential solar and utility-scale solar down to 6% or so is a worthy use of energy. I keep asking, "What about the cost of acquiring these projects and the low margins?" Nobody wants to deal with that.

MR. MARTIN: Tokenize meaning an initial coin offering?

MR. BRANDT: Yes. They would do an initial coin offering and then effectively have it trade off the value of the cash flows.

MR. MARTIN: Meaning sell access to a platform where people can buy electricity? You buy a token. You can get on the platform.

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MR. BRANDT: No. The purchasers of tokens are buying and selling cash flow and not the right to take electricity.

MR. MARTIN: People are raising hundreds of millions of dollars through such offerings.

MR. WOOD: Ted, the Securities and Exchange Commission wants to speak with you after this panel.

MR. BRANDT: We have not accepted any of these assignments, I just want you to know.

MR. MARTIN: Not yet. The SEC chairman last week suggested the SEC does not think ethereum and bitcoin are securities.

Shorter PPAs with merchant tails are becoming the norm. Developers are taking more basis risk.

MR. GIORDANO: Susan Nicky mentioned something before this panel that I think is also a big piece of maturation of the capital stack for renewables generators. We are moving to a much smarter grid with smarter meters.

MS. NICKEY: Renewable generators who have added energy storage or put in smart controls feel like they can bid forward in the day-ahead market and gain extra revenue by using storage to offer power during peak hours instead of overnight. These changes can have a meaningful effect on revenue.

MR. MARTIN: Storage allows tapping into as many as 13 additional revenue streams. Storage is more of a software than a hardware play. You need a brain to decide which revenue streams to tap at any given time. What percentage of projects do you see having storage today as a component? 25%? 10%? Less?

MR. BRANDT: For new projects, it is closer to 25%. Virtually every RFP we see today has a storage component. The only issue is whether storage is mandatory or optional. I think storage is already upon us.

MS. NICKEY: I think the market is still evolving. We do not see it so much in what we are financing today, but we expect almost all solar will have storage in the future. A few wind-plus-storage projects have been awarded power contracts recently.

Debt Rates

MR. MARTIN: Let's move to a rapid question round. Ray Wood, you mentioned that there is no major drive currently to reduce the cost of capital because the market remains awash in capital. There are 70 to 90 project finance banks chasing deals. How much longer can that continue before there is a shake out?

MR. WOOD: Banks really do not play the primary role in the energy sector. Non-banks do. The only thing that will chase the banks from the market is if there are no longer contracted revenue streams to support the financing.

Contracted assets are earning an acceptable return on risk capital. The regulators are fine with them. If anything, regulatory pressures are easing in the bank sector, at least in the United States.

MR. MARTIN: Some banks are now offering to lend construction debt at less than 100 basis points above LIBOR. We even heard one bank say last week that it is offering 75 basis points. Have you seen construction debt actually close at these levels?

MR. GIORDANO: We have not seen any construction debt below 100 basis points. I would ask what other balance-sheet support there is to support that type of spread.

MR. BRANDT: I think you are hearing these numbers in build-own-transfer arrangements, and it is important to understand that those are different animals. You have an investment-grade utility that agrees to buy the project at the end of construction. You have a developer that needs financing in order to deliver the project with no conditions precedent to the project sale that cannot be insured against. The risk of a take out for the construction lender is really, really small. It is equivalent to financing a trade receivable from a customer with strong credit.

MR. MARTIN: What do you think is the current margin above LIBOR for construction debt?

MR. WOOD: We normally expect to see 150 to 225 basis points.

MR. MARTIN: Are the margins continuing to tighten? They have come in by at least 25 basis points since the start of the year. They had reached that level by mid-spring. Have you seen any further margin compression since then?

MR. BRANDT: Not from our perspective, no. But we are seeing projects that are at a slightly later stage than construction.

Development Platforms

MR. MARTIN: Many sponsors are trying to sell development platforms this year. There are also a lot of projects for sale. Is this due partly to a sense that prices may be at a peak or close to it or is there something else driving this trend?

MR. WOOD: The amount of working capital needed to develop projects has increased.

Developer returns have been very good for the last three or four years, so you are seeing a wave of development platforms for sale, and there is a large demand for them. The deals are generally structured with some cash up front and an earn out, so there tends to be a pretty rigorous alignment of interests.

MS. NICKEY: There is a huge pipeline of projects that will require a lot of capital to develop. Another driver is there are global players in the US market who use IFRS accounting and may be looking for partners to allow deconsolidation. HLBV accounting in tax equity partnerships adds complexity for these types of sponsors.

MR. BRANDT: I think Ray touched on some of the drivers for the developers or sellers. Turning to the buyers, many of them are Asian, and they are copying the European business model of using their balance sheets to de-risk projects and then selling down their positions to pension funds. They are actively looking at the few available remaining wind companies for sale and the more significant number of solar development platforms for sale in what is a more fragmented market segment.

MR. MARTIN: Ted Brandt, at what discount rates are wind and solar development platforms trading?

MR. BRANDT: The answer differs depending on whether you are buying a whole portfolio or a specific project. Even though risk-free rates, meaning Treasury bond yields, have moved up from 210 to almost 300, we are seeing bidders discount projected cash flows from utility-scale solar projects at 6.5% to 7%, maybe 7.5%, on an unleveraged, after-tax basis assuming 35 years of revenue. There is a huge issue how to look at the merchant curves. We are seeing rates of 8.25% to 9.5% for wind, depending on the length of the power contracts and how one looks at merchant curves.

MR. MARTIN: Are you representing primarily sellers or buyers, or both, at this point?

MR. BRANDT: A lot more sellers than buyers, but we do both.

MR. MARTIN: Ray Wood, you see a lot of the market. Do these discount rates seem right?

MR. WOOD: I think Ted was referring to asset-level discount rates. If you are talking about a platform, you have have to probability-weight the development pipeline, and bidders tend to want higher returns than when bidding on what is essentially contacted cash flow from individual assets or a portfolio of operating projects.

With a developed flip or developed sell and recycle, we see people looking for more traditional equity-growth returns. The strategics who are bidding want wind development, solar development, battery development, as well as retail access. They are trying to put all these things together for some sort of storefront that will be the 21st century utility. Whether they might be prepared to bid at lower discount rates because they believe they are getting synergy with other assets is hard to say.

MR. MARTIN: You just pointed us to an interesting topic for another day. Michael Polsky, who spoke just before this panel, left us one as well on the renewables paradox. The more renewables there are, the lower the prices go and the harder it is for anybody to make money.

About a dozen years ago, Polsky began advocating for renewable energy companies to be able to organize themselves as master limited partnerships. Now that the natural gas pipelines seem to be abandoning this structure, should the industry still be pushing on Capitol Hill for the ability to use MLPs? How important are they?

MS. NICKEY: The survey on which Greg Wetstone reported earlier has MLPs at the bottom of the wish list. I understand there was a provision in the tax reform bill at the end of last year that had a materially negative impact on MLPs. When the pass-through nature of MLPs no longer offers the same economics as before, it dries up the advantage.

MR. WOOD: I agree with that. Let's see when yield cos can recover. Yield cos are trading today at */ continued page 64*

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a level that is closer to the intrinsic value and once yield co shares get growth wedged back into them, they will once again become a currency that can be used to make acquisitions or roll-ups.

An MLP is in the same grouping, but it has unique tax disadvantages. I do not see it being a relevant player in this space, absent tax law changes.

MR. MARTIN: Let's move to audience questions.

MR. DAVIES: Ken Davies, Microsoft. The more we look at these assets, the more they look to us like commercial real estate, whose modus operandi is not project finance, but CLOs. If these projects are, in the end, commercial real estate, what is the floor for the cost of capital?

MR. GIORDANO: The major difference between real estate and renewable assets is residual value. Typically when you buy real estate, it increases in value over time. Industrial assets might go sideways. Whereas a 20-year-old wind farm will be worth some percentage of its original cost.

The hmarket has moved to using a dual rate, a discounted-cash-flow analysis where the contracted revenue stream is discounted at one rate and then a more conservative assumption is made for the merchant revenues.

This is probably different than the way most commercial real estate projects would be evaluated.

Corporate PPAs

MR. HAUG: David Haug, Arctas Capital. Is one of the reasons why so many development platforms are for sale is that developers see fewer and fewer PPAs for shorter and shorter tenors, and corporate PPAs, which are a growing share of the market, are pricing electricity at the hub rather than the node, creating basis risk. What effect do you see this having on the ability to raise debt and tax equity? Do you see the market moving to where shorter PPAs plus merchant tails become the norm?

MR. GIORDANO: I think we are largely there.

As offtakers begin to realize the impact that some of their risk aversion is having on their ultimate cost of energy, it might create opportunities for developers and offtakers to work together to find better ways to handle the risks that will produce a more optimal capital structure.

Right now, you are seeing a lot of risk being pushed down to the project level. The financiers are still figuring out how to price that risk, including what assumptions to make for purposes of pricing.

The tax equity market has become more sophisticated. Using things like pay-go structures to address basis risk might make sense. Or else tax equity investors may come to realize that they are protected from basis risk through delay in the flip date. Maybe with that realization we will see more tax equity willing to take full-on merchant risk.

MR. WOOD: We seeing tax equity portfolios with seasoned projects being resold in the secondary market. It is not a super-liquid secondary market, but the fact that there is such a market is a big step from where we were.

Projects that do not flip on time, but have cash and no more tax attributes, give the tax equity investors returns that are on a par with equity returns. At that point, the tax equity investor is really the major equity in the project.

MR. BRANDT: As I think about the financing constraints and whether a project with no contract or a very short contract can get financed, I do not think the debt or cash equity will be the constraint. The constraint will be the tax equity. If tax equity can be raised, then everything else will get done because of the amount of liquidity in the debt and equity markets.

MS. NICKEY: Good news then, because we said there is more tax equity after tax reform than before.

Many corporations are now moving to buy renewable power. As people learn more about basis risk, there will be innovation. We are seeing innovation on the utility and offtake side — green tariffs in Michigan, things that are happening in Virginia — that are allowing the market to expand for renewables and transfer the risk where it can be better-managed. ◎

Opportunity: Electric Vehicle Charging Infrastructure

by Ben Grayson, in New York

Many think the charging infrastructure for electric vehicles will end up in utility rate bases, but several companies are hoping to prove the utilities wrong by testing alternative business models.

Various car manufacturers have announced dramatic increases in electric vehicle production in response to domestic and international pressure to electrify the transportation sector. Prices of lithium-ion batteries are falling.

Manufacturers face a chicken-and-egg problem that has long surrounded scaling electric vehicle production: there is a need for investment in charging infrastructure before consumers will feel comfortable moving *en masse* to electric cars, and investors need confidence that significant consumer demand for such cars exists to support returns.

Solving this problem has not rested solely with utilities, but has brought together an entire ecosystem made up of financiers, hardware and software providers, auto manufacturers and governments.

This article describes some of the private investment models in EV charging infrastructure and highlights the government and utility incentives surrounding the EV marketplace generally.

Private Business Models

Charging stations can generate four revenue streams: energy use fees, per-use user fees, subscription fees and onsite advertising.

Depending where the charging station is located, the owner may be subject to regulatory oversight if it collects revenue on an energy use basis. This is because the owner will be considered a "utility" since it is supplying electricity at retail. However, some states make exceptions for vehicle charging stations.

A threshold business decision involves whom to have own the charging stations. ChargePoint and EVgo are interesting case studies. Each uses a different business model.

ChargePoint is the largest global operator of an EV charging network with more than 50,000 charging stations. It does not own stations; it owns the underlying technology and sells stations to retailers, workplaces, hospitals, cities and others after developing and connecting the stations to its network. The stations can be accessed through a smartphone app. CEO Pasquale Romano likens the company to Airbnb, which can be seen as the largest hotel chain in the world, but does not own a single hotel.

ChargePoint generates returns in three ways: by selling charging station hardware to property owners, by offering its cloud-based software services, and by offering operational services such as maintenance, repair and support.

Under the ChargePoint model, property owners pay to have a charging station put on their property. The ChargePoint stations are networked, meaning that they are intelligent and property owners are able to manage who uses the station, pricing policy and power levels.

While owners set their own charging rates, the company provides rate setting consulting services. Unlike Tesla, whose charging business is designed only for its own cars, ChargePoint is agnostic as to car model. Drivers on the network can use the app to locate nearby charging stations, determine station availability, receive charge notifications and pay for charging. ChargePoint collects and remits the payments from drivers to the station owner.

ChargePoint has partnered with auto manufacturers to install ChargePoint software directly into vehicles. Daimler and BMW as well as Siemens own significant stakes in the company.

ChargePoint partnered with Key Equipment Finance in 2013 to create a lease-to-own program where business owners could pay as little as $3 per day to lease a charging station that costs $6,000 to install, according to published reports. The owners recouped costs by charging drivers a fee for service. The leases were structured as capital leases, allowing business owners also to claim a federal tax credit for charging stations, which was 30% for costs up to $37,000 per address installed in 2013. Key would buy the charging stations, check creditworthiness of owners, work out lease terms and pay for electrical contractors for installations. ChargePoint managed the stations and the network as lessee.

EVgo, which uses a different business model, is a public fast charging network, originally created by NRG. The network currently has more than 1,000 chargers in 66 metropolitan markets.

Unlike ChargePoint, EVgo owns and operates its stations and sets its own pricing. EVgo bears all of the risk of investment and relies on earning a profit from the sale of its service.

EVgo recently simplified its pricing / continued page 66

Electric Vehicles

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scheme, offering customers two different options for charging: a pay-as-you-go rate and a fixed monthly membership price. EVgo says its membership pricing will be on par or cheaper than average gas-powered vehicles on a per-mile basis. Special pricing deals are available for buyers of EVgo's manufacturer partners, Nissan and BMW.

Auto manufacturers have much to gain from widespread charging infrastructure. Nissan partnered with EVgo to provide free public charging to its drivers for the first two years of car ownership.

In July, BYD, a Chinese electric vehicle company, and Generate Capital, a clean-energy financing company, formed a joint venture leasing program focused on electric vehicles to make it easier for cities and counties to replace their bus fleets.

There are about 345,000 electric buses in use today globally. Only around 300 are used in the US. Municipal governments are often strapped for cash and usually reluctant to upgrade existing bus fleets, even if doing so could save them money on repairs and other operating costs. Leasing buses instead of buying them reduces the cash outlay required up front.

Generate Capital will invest $200 million to buy and lease the buses. BYD and Generate Capital will continue to own the batteries, which still have a use in stationary storage applications. BYD can recycle the battery for a new bus customer after the bus lease where the battery was originally deployed ends.

Buses and trucks tend to be more expensive than cars, so financing can be a larger obstacle. Seeing financing companies partner with manufacturers may become a popular way to offload burdensome upfront costs that constrain transit agencies and trucking companies from replacing their existing fleets.

New business models are being tested for deploying charging stations for electric vehicles.

Variations

Demand response is another way owners of charging stations might earn additional revenue.

Grid-scale demand response aggregates a network of grid-connected charging stations into a single unit of demand. Utilities will make payments to network operators in return for an agreement to back down load during periods when the grid needs to reduce electricity demand.

The demand-response model is trending for residential charging stations. The model is less popular for public charging stations where customers pay for charging as a service and are less inclined to be inconvenienced by shifting their charging times. eMotorWerks, a company recently acquired by Enel, markets a smart grid charging platform specifically for EVs.

State Incentives

In 2017, there were 53 pending actions in 21 states and the District of Columbia related to incentives for electric vehicles and charging infrastructure. The initiatives are wide-ranging and look across the entire EV value chain. They range from special utility rates to encourage EV charging to rebates, PACE financing and zero emissions mandates directed at auto manufacturers.

Starting with special rates, PG&E offers two residential EV rates: one that combines the EV electricity costs with those of the residence, and one that keeps the EV electricity costs separate. The lowest rates are offered between 11 p.m. and 7 a.m. Southern California Edison offers an EV rate plan with off-peak pricing between 9 p.m. and 12 p.m. that is charged separately from the residential electricity and a time-of-use rate plan with off-peak pricing between 10 p.m. and 8 a.m.

In New York, Consolidated Edison offers a whole-house residential time-of-use rate for EV charging, and a non-residential time-of-use rate for EV charging with a separate meter. Hawaii has experimented with a tariff program that simultaneously creates time-of-use pricing between utilities and EV charging facilities and then EV charging facilities and customers.

In Rhode Island, the Narragansett Electric Company asked as part of its general rate case for an off-peak pilot program where participating customers receive rebates of 6¢ a kilowatt hour during the summer months and 4¢ a kilowatt hour during winter. The rebates are paid on electricity used during off-peak charging hours.

Aside from rates, utilities and states are also offering financial incentives to buy charging hardware. For example, the Sacramento Municipal Utility District is offering residential customers either a $599 rebate or a free level-two charger for SMUD customers who purchase or lease electric vehicles.

Oregon has made EV charging infrastructure eligible for PACE financing. PACE programs allow property owners to borrow money to pay for certain clean energy improvements and repay the amount borrowed essentially as additional property taxes through a special assessment on the property.

Some states participating in the Regional Greenhouse Gas Initiative, called RGGI, are considering use proceeds from auctioning greenhouse gas allowances, Volkswagen settlement funds and state public benefit funds to fund consumer rebate programs and other initiatives to support the EV industry.

The California Public Utilities Commission approved a plan in May to expand EV infrastructure and rebate programs with a budget of $750 million. Around the same time, the New York governor's office announced a pledge of up to $250 million through 2025 to its EV expansion initiative called Evolve NY. The New York Power Authority will work with the private sector to install up to 200 DC fast chargers along its interstate corridors with the goal of making them available every 30 miles. Similarly, the Public Service Enterprise Group in New Jersey announced a $300 million pledge to build out up to 50,000 charging stations along highways, in residential areas and at workplaces.

California, which is among the more ambitious states on EV policy, currently has a zero emission vehicle mandate, requiring 15% of new vehicles to be zero emission vehicles by 2025. The Trump administration proposed new rules in early August that challenge California's right to set its own tailpipe pollution standards that are more stringent than the federal government's. The action would nullify the mandate.

The mandate currently in place requires manufacturers to accumulate credits based on their average sales in California over the three model years preceding the last. For example, the 2018 requirement is based on sales of 2014, 2015 and 2016 model-year vehicles. The amount of credits a manufacturer receives varies based on range battery efficiency and the type of vehicle sold. The program is dynamic in the sense that automakers that accumulate more credits than they need can bank credits for future use up to a certain amount and can transfer credits to other states and sell or trade credits with other manufacturers. Other states may be quick to adopt similar mandates to compete for sales. They may also enact legislation that allows for regional cooperation as they have done with cap-and-trade programs. ◎

California Update

by Jim Berger, in Los Angeles

Two bills have been proposed in the California legislature that could affect renewable energy companies in California: SB 100 in the state senate and AB 813 in the state assembly.

100% Renewables

SB 100 would set a goal of 100% of retail sales of electricity in California to come from eligible renewable energy and other zero-carbon sources by the end of 2045. The bill is scheduled for floor votes in both houses of the California legislature as soon as August.

Current law requires each utility or other load-serving entity to deliver at least 50% of its energy from eligible types of renewable energy by 2030, with interim targets of 40% by 2024 and 45% by 2027. The investor-owned utilities in California are already on track to meet the 50% goal by 2020, 10 years ahead of schedule.

The proposed new law would make two important changes. First, it would increase the existing targets without changing the dates. The new targets would be 44% by 2024, 52% by 2027 and 60% by 2030. The proposed law does not establish subsequent targets other than the overall policy of 100% by 2045. However, it would direct the public utilities commission to establish appropriate three-year compliance periods for after 2030.

Because the renewable energy production has consistently outpaced California's legal requirements in past years, this proposal to leave the setting of post-2030 targets until the future gives the public utility commission the ability to respond better to the facts on the ground.

Second, the proposed new law would allow the targets to be met not only from renewables, but also other "zero-carbon resources." SB 100 does not define "eligible renewable energy resources," but the category presumably would include everything that is eligible under current law: biodiesel, biomass, bio-methane, fuel cells using renewable fuels, geothermal, certain kinds of hydroelectricity, municipal solid waste, ocean wave, ocean thermal, solar, tidal current and wind. SB 100 also does not define "zero-carbon resources." The category could presumably include nuclear energy, but it seems unlikely that it is intended to include nuclear since California is shutting down its last nuclear power plant by 2025.

Under existing law, municipal utilities are not required to deliver more than a specified minimum quantity of renewable energy under the program if more than 50% of their retail sales are from large hydroelectric facilities. Large existing hydroelectric facilities in California are not considered renewable energy for this purpose. Hydroelectric facilities are not eligible if they are larger than 30 or 40 megawatts, depending on the circumstances. The 50% threshold would be reduced to 40% under SB 100. The intention seems to be to shift slowly away from hydroelectricity.

The coming electrification of the transportation sector is expected to make the power industry a larger source of greenhouse gas emissions and to make the transportation sector a smaller contributor to greenhouse gas emissions. SB 100 would also encourage conversion of buildings and ports from natural gas to electricity.

Shifting the energy use from oil in the transportation sector and natural gas in the building and port sector to electricity will increase overall electricity consumption, making it more difficult for utilities to meet renewable energy targets. Advocates for the higher renewable energy percentages do not want them to prevent utilities from taking actions to reduce overall greenhouse gas emissions.

SB 100 requires that policies be adopted by the end of 2020 to remove any disincentives to tackle greenhouse gas emissions.

The proposed law suggests one policy to be considered is to provide an allocation of greenhouse gas emissions allowances to utilities and other retail electricity suppliers as a way of acknowledging that a shift is unavoidable in greenhouse gas emissions from transportation to power and from converting buildings and ports from natural gas to electricity end uses. The proposed law does not provide any more details.

SB 100 says it would require 100% renewable energy while "not increas[ing] carbon emissions elsewhere in the western grid." This is important when considering another recent proposal, AB 813.

Electrification of the transportation sector is expected leave power companies exposed as the next largest source of carbon emissions.

Reducing Carbon

AB 813 is called "Multistate Regional Transmission System Organization: Membership." It passed the California assembly in 2017, but did not reach a vote in California's senate. It was carried over to the current session and approved by the senate energy committee in June. Governor Jerry Brown (D) has been pushing this as a signature issue in the last few months of his term in office.

AB 813 would transform the California Independent System Operator (CAISO) into a regional transmission organization.

The intention is to create a regional grid that includes more than just California as a way to reduce costs for consumers and increase the use of carbon-free energy. For example, when California is producing too much solar energy, it could be more easily shipped to neighboring states and vice versa.

Critics worry that this will allow dirty electricity, such as electricity from coal plants in Wyoming, to come into California. SB 100 is supposed to prevent this. AB 813 would also bar California entities from joining any regional transmission organization if the governing rules of that regional grid do not protect and preserve a state's authority over matters regulated by the state, including energy procurement policy and resource planning.

AB 813 also includes other measures to promote California's environmental and energy goals. For example, the proposed law would require the new state RTO to "maintain a transparent system for tracking emissions of greenhouse gases resulting from resources dispatched to serve the California load."

It is difficult to pin down the net effects of AB 813. The bill should help some projects since any given project could have a larger pool of customers to which it can sell. Projects may also be able to get a better price from an out-of-state customer than an in-state customer. It might also reduce curtailment of power plants by making it easier to send excess power out of state at times when production would otherwise have to be curtailed. At the same time, in-state electricity generators could have more competition, which would mean lower prices. ◎

Environmental Update

The Trump administration announced plans in early August to roll back Obama-era automobile emissions and fuel efficiency standards and to revoke the long-standing authority of California and other states to impose stricter standards than those imposed nationally.

The joint move by the US Environmental Protection Agency and the US Department of Transportation is another step toward dismantling programs to limit greenhouse gas emissions that contribute to climate change.

The plan would undo a 2012 rule that requires automakers to achieve average fuel economy for passenger vehicles of about 54 miles per gallon by 2025. Instead, average fuel economy standards would be frozen at around 37 miles per gallon after 2021. The plan would also undo a requirement that automakers build more fuel-efficient and less polluting cars, such as electric vehicles and hybrids.

Many automakers had opposed the 2012 rule as overly burdensome. The Trump plan goes significantly farther than most automakers had requested.

It sets the stage for another epic legal battle that will introduce a period of regulatory uncertainty for the auto industry for years to come, whether or not the Trump administration survives past 2020. Even if the next administration were to withdraw the Trump action, reinstating the 2012 rule would also land in the courts. A settled policy would have to be re-litigated.

Accordingly, heavy pressure is being brought to bear not only from environmentalists, individual states and consumer groups, but also from some automakers to change the plan before it is finalized.

California has had dispensation by waiver to set stricter air pollution standards than those imposed nationally since 1970. More than a dozen other states have also been given similar waivers. The Trump plan would revoke these waivers.

California is the nation's biggest state market for autos with more than two million new cars and light trucks sold in 2017. California and a dozen other states that follow its vehicle rules account for more than a third of US auto sales.

With such a large market share, the California standards have effectively displaced the federal auto emissions and efficiency standards.

The Trump administration argues that the lighter cars required to meet the California fuel efficiency standards will lead to more highway deaths.

By barring states from adopting their own standards, the administration will make it harder for states that want to try to comply with the Paris climate accord to do so. California and a number of other states have said they plan to comply with goals set in that accord for greenhouse gas reductions even though the United States has formally withdrawn from the accord.

The attorneys general of nearly 20 states have filed suit or announced plans to sue to try to block the latest Trump action.

California responded on August 8 by reaffirming that it expects automakers to comply with state law, even if the Trump administration weakens emissions and fuel efficiency standards that the state set jointly with the federal government during the Obama administration. The action merely bolsters the state's legal footing in advance of the looming legal battle. The state is collecting comments through September 24.

Trump is moving to block states from imposing stricter auto emissions standards than are imposed nationally.

Both California and federal officials have suggested that a deal could be reached. California said it is willing to consider adopting new "flexibilities that reduce compliance costs" for automakers while still driving down greenhouse gas emissions.

Other major auto markets in Europe and China are continuing to tighten tailpipe emissions standards and require higher fuel efficiency.

NEPA Reform

The Council on Environmental Quality or CEQ — an office within the White House — announced in late June that it plans to update the implementing regulations for the National Environmental Policy Act.

NEPA requires federal agencies to prepare environmental impact statements for all "major Federal actions significantly affecting the quality of the human environment." CEQ guidelines govern how the agencies must go about preparing these statements.

The CEQ rulemaking will be of particular interest to developers, lenders and investors in energy and other large-scale infrastructure projects as NEPA reviews can delay permit issuance and project completion.

CEQ issued an "advance notice of proposed rulemaking" on June 20 asking the public for comments about what it should do. The abbreviated deadline for commenting on the notice was in July.

President Trump issued an executive order in August 2017 called "Establishing Discipline and Accountability in the Environmental Review and Permitting Process for Infrastructure Projects." The executive order is No. 13807.

It directed CEQ to implement a "one federal decision" policy and modernize the environmental review and authorization process under NEPA. Under the one federal decision policy, all the federal agencies involved in the NEPA review and environmental permitting of a major infrastructure project are required to develop a single permitting timetable, prepare a joint environmental impact statement where warranted, and issue all project approvals within 90 days after an agreed "record of decision" is signed.

CEQ has declined to impose hard-and-fast time limits on agencies in the past, leaving timing decisions to the agencies conducting their respective environmental reviews. This time, it is expected to adopt time frames to which 12 federal agencies agreed in an April 9, 2018 memorandum of understanding. These were consistent with the executive order.

Among the issues on which CEQ is seeking comments are whether key NEPA terms should be redefined. Such terms include "major federal action," "significantly" and "cumulative impact." The current definitions were last revisited in 1986. How these terms are defined can affect whether NEPA applies to a particular project at all.

CEQ also wants input on what the government should focus in its NEPA reviews. CEQ could end up following the lead of a recent Federal Energy Regulatory Commission order that limited consideration of upstream and downstream greenhouse gas emissions when evaluating natural gas infrastructure projects.

Endangered Species

The Trump administration proposed in July to end the practice of automatically extending the same Endangered Species Act protections to species that are merely "threatened" as are given to species that are considered "endangered."

The joint proposal by the US Departments of Interior and Commerce would instead make decisions on whether and how to protect threatened plants and animals on a case-by-case basis.

The Endangered Species Act was enacted during the Nixon administration in 1973. It protects plant and animal species by designating them as endangered or threatened. Either label makes it illegal to kill such species and requires preservation of their habitats. The law protects more than 1,600 plant and animal species.

The Trump administration would also allow regulators to take into account the economic impacts when deciding how wildlife should be protected. Currently, regulators are directed to make such determinations based solely on the best scientific and commercial evidence.

The administration is also proposing to change the definition of "foreseeable future." Federal agencies are required by law to determine whether a species */ continued page 72*

Environmental Update

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is "in danger of extinction, or likely to become so within the foreseeable future" in making a decision on whether to list a species as endangered or threatened. The administration would like to limit the foreseeable future "only so far as we can reasonably determine that the conditions posing the potential danger of extinction are probable," an Interior Department spokesman said.

High Court

Brett Kavanaugh, whom President Trump has nominated to the US Supreme Court, has a record of questioning how far the Environmental Protection Agency can go in regulating greenhouse gas emissions. A number of EPA-related cases have come before the US appeals court on which Kavanaugh currently serves. He has had a tendency to read environmental statutes narrowly.

"Climate change is not a blank check for the President," Kavanaugh wrote in an August 2017 opinion striking down large portions of Obama EPA limits on a greenhouse gas used in refrigerants. "However much we might sympathize or agree with EPA's policy objectives, EPA may act only within the boundaries of its statutory authority."

Kavanaugh is also a believer in following court precedent even when he disagrees with it. For example, in 2013, he sided with environmentalists against the EPA in a case in which several industry groups were trying to exempt emitters of biogenic carbon dioxide from the need for permits.

Justice Kennedy, whom Kavanaugh would replace, often showed a similar skepticism of agencies pushing the bounds of their statutory authority. However, Kennedy was the deciding vote in a number of landmark environmental cases, including a 2007 decision in Massachusetts v. EPA that concluded EPA is required to regulate greenhouse gases as an air pollutant under the Clean Air Act. ◎

— contributed by Andrew Skroback, in Washington and New York

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has 4,200 lawyers in 58 offices in 33 countries.

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