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Cost of Capital: 2020 Outlook

A group of industry veterans talked in late January about what to expect in the year ahead for tax equity, bank and term loan B debt and project bonds in a widely heard conference call. The US market remains awash in liquidity. There is intense competition among banks to lend. Interest rates remain under downward pressure. Tax equity deal volume is expected to set a record in 2020, making it wise to get financings closed as early in the year as possible as resources needed to finish projects and close deals will be in increasingly short supply as the year wears on.

The panelists are Yale Henderson, managing director and head of energy investments for JPMorgan, Jack Cargas, head of originations on the tax equity desk at Bank of America, Ralph Cho, co-head of power for North America for Investec, Jean-Pierre Boudrias, managing director and head of project finance for North America at Goldman Sachs, and John C.S. Anderson, global head of corporate finance and infrastructure at Manulife. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity

MR. MARTIN: Yale Henderson, what was the tax-equity volume in 2019, and how did it break down between wind and solar?

MR. HENDERSON: The market last year was comparable to 2018. The market did about $12 billion in tax equity in 2018. It was in the same $12 to $13 billion range in 2019.

The breakdown was roughly 65% wind and 35% solar, plus or minus 5%.

These figures for market size are fundings and commitments / continued page 2

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CORONAVIRUS has led some equipment suppliers who rely on Chinese factories to send force majeure notices that deliveries will be delayed.

This causes two complications.

Some renewable energy developers paid at year end 2019 for equipment to be delivered within 3 ½ months after payment, hoping to count the payment toward a 5% test for starting construction. Solar projects had to be under construction for tax purposes by the end of 2019 to qualify for an investment tax credit at the full 30% rate.

One way to start construction is to "incur" at least 5% of the project cost before the deadline. Costs are not normally / continued page 3

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made during the year. The biggest difference we saw between 2018 and 2019 was most, if not all, of the $12 billion was fully funded by the end of 2018, unlike 2019 when not everything got done, and we move into 2020 with spillover.

That means little rest for the tax-equity providers. Everyone has a lot of deals to close in the first quarter.

MR. MARTIN: So a lot of momentum moving into 2020. Jack Cargas, you told me you closed a startlingly large number of deals in the last couple of weeks of 2019. What was the number?

MR. CARGAS: We closed or funded nine transactions in the last two days of the year.

MR. MARTIN: I assume JPMorgan was also extremely busy?

MR. HENDERSON: We did more than $1 billion in fundings in the last week of the year.

Renewable energy deal volume is expected to set a record in 2020.

MR. MARTIN: What do you expect in 2020?

MR. HENDERSON: More of the same. The market will be much larger: probably close to $15 billion. We are seeing a volume of deals that have already been awarded, but not yet executed, that is significantly higher than during the comparable period last year. We see a lot of big deals in the pipeline still to be done. We hope the deal flow will be spread over the year rather than be back ended. A large number of wind farms commenced construction in 2016 and will have to be completed by the end of 2020 to qualify for federal tax credits. That may contribute to a traffic jam at year end.

MR. CARGAS: We hear observers predicting an increase in demand for tax equity in 2020 by as much as two times. Some of that is due to the hangover that Yale mentioned. There were several hundred million dollars of planned wind tax-equity fundings that were delayed from 2019 into 2020 for sponsor-specific reasons, usually construction delays. Then you have the crush of wind projects that need to be completed by year end. All of that suggests a significant increase in demand this year.

MR. MARTIN: Two times volume suggests $24 billion in demand. Trying to shoehorn that amount of demand into a $15 billion tax equity market may be a challenge.

What percentage of the typical solar project is tax equity as we enter 2020?

MR. CARGAS: For solar, probably less than 40%. The percentage shrank as a result of the so-called tax reforms. A couple of years ago when the federal corporate tax rate decreased from 35% to 21% and tax losses became less valuable to tax-equity investors, the tax equity share of the capital stack declined. It was probably closer to 50% before, and now it is less than 40%.

MR. MARTIN: What about wind?

MR. CARGAS: Similar phenomenon. Wind tax equity had been as much as 60% to 70% of the capital stack and now, after tax reform, it is more like 50% to 60%.

MR. MARTIN: Yale Henderson, do you agree with those numbers?

MR. HENDERSON: Yes.

MR. MARTIN: Many listeners patch into this call to get a better feel for what cost of capital to assume in bids to supply electricity. Tax equity flip yields fell during the past year. They seem to be in the 6.25% to 6.8% range for most utility-scale wind and solar projects. Some larger wind developers reported flip yields a little below 6%. Solar residential rooftop companies seemed to see pricing in the 7% to 8% range. The cost of tax equity is a function of demand and supply. Jack mentioned that demand is expected to skyrocket. In which direction do you sense the cost of tax equity will move this year, if at all?

MR. CARGAS: We are always happy to discuss details around after-tax IRRs with our customers, but perhaps on a less public and more one-on-one basis. What you said about the direction in which yields moved last year is accurate. The future is notoriously hard to predict. While it is accurate to say the primary driver on tax-equity yields over time has been demand and supply, the cost of capital to investors has also become important as well as a few other factors such as the amount of competition for deals. The most attractive projects draw a lot of interest from potential tax equity investors.

Structures are changing significantly enough for there to be some level of yield premium for transactions that the market views as more risky, such as residential solar portfolios with low FICO scores, solar projects presenting basis risk and a whole host of other things. Other factors besides demand and supply have been playing a bigger role lately in the cost of tax equity.

MR. HENDERSON: I agree with Jack. As we have talked about before, flip yields are not created equal. The nature of the project, its location, the shape of the cash flows, the offtaker or hedge counterparty credit are just a few of the factors that play into the after-tax IRR. Some after-tax cash flows are more valuable than others in terms of how they flow through the book return for an investor.

The range you cited is pretty close. Some numbers are higher than that range depending on the project attributes and the length and source of the contracted revenues.

MR. MARTIN: Deficit restoration obligations — DROs — last year were 40+% in many deals. Do you see any change going into 2020?

MR. HENDERSON: No. There should not be that much structural change, but the less cash there is in a deal due to low electricity prices, the more pressure there is for higher DROs. The maximum DRO size is one piece of the puzzle. The timing and reversal of the DRO are important elements in how high an investor will be prepared to go.

MR. MARTIN: Both of you mentioned that this year is the deadline for wind projects that started construction in 2016 to be in service. If construction started in 2016 by incurring at least 5% of the cost, the developer can buy more time from the IRS by proving continuous efforts were made to advance the project after 2016. Will we see the tax equity market willing to accept continuous efforts to finance projects in 2021 that started construction in 2016?

MR. CARGAS: That's a tough question. We ran into something similar in the past, and it proved difficult for the sponsors involved to provide full evidence to document the continuous efforts. It is not clear yet what will happen for projects whose construction slips into 2021.

We encourage sponsors to make / *continued page 4*

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incurred until equipment or services are delivered, with the exception that a payment at year end counts if equipment is "reasonably expected" to be delivered within 3 ½ months after payment. This 3 ½-month rule is a "method of accounting." Some developers need IRS permission to use it.

Some tax equity investors have been requiring actual delivery within the 3 ½ months. However, IRS regulations require only that delivery or title passage was "reasonably expected" when the payment was made.

Delays could also cause problems for wind developers whose projects must be completed by the end of 2020 to qualify for tax credits. Tax credits for wind projects have been gradually phasing out since 2016. Projects on which construction started in 2016 qualify for tax credits at the full rate, but it is not enough to have started construction in time: most projects must then be completed within four years after the year construction started to qualify for any tax credits.

There are two ways to start construction. One is under the 5% test. The other is by starting "physical work of a significant nature" at the project site or at a factory on equipment for the project.

Projects on which work started under the 5% test can get more time by proving "continuous efforts" have been made to advance the project since the year construction started. A delay caused by coronavirus is an excusable disruption that can explain a gap if there was otherwise a continuous effort.

Most projects that started construction based on physical work will be out of luck.

Both Bank of America and JPMorgan are still assessing whether they will finance 2016 projects that slip into 2021. They accounted in 2019 for roughly half the tax equity market.

Developers who receive force majeure notices should / *continued page 5*

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sure projects are in service before the cliff so that we do not have to have this discussion. We do not know what logs ought to look like. Should they be monthly, daily, hourly — that's just one of many questions in this area.

MR. MARTIN: Yale Henderson, I think you said something similar at an offshore-wind conference this fall.

Have either of you seen any tax-indemnity claims made on renewable energy projects and, if so, around what risks?

MR. HENDERSON: Actual claims? I am not aware of any, other than the well-documented issues around tax basis under the Treasury cash grant program.

Tax equity volume in 2020 is expected to hit $15 billion, up from $12 to $13 billion in 2019.

MR. CARGAS: We have made no such claims on our portfolio.

MR. MARTIN: Do either of you have a rule of thumb for how large a step-up in tax basis you are willing to accept above the cost to construct?

MR. CARGAS: We do not have a fixed rule of thumb. We are aware that the Treasury suggested during the section 1603 program that step ups should normally not exceed 10% to 20%. That does not mean that we can go straight to 20%. The facts and circumstances may say that it ought to be 10% or 12% or 15% or 23%. Twenty percent is not necessarily a cap either. It comes down to the specific facts and circumstances.

MR. MARTIN: Every project seeking tax equity at this point had to be under construction by a deadline. I know you prefer that developers incur at least 5% of the cost. However, many developers have moved to a less expensive approach of relying on physical work on such things as transformers. Are you financing projects based on transformers? How much work do you need to see on the transformer before the construction-start deadline?

MR. HENDERSON: We are willing to work with transformers. Obviously more work is better than less. Certainly if you just have a conservator tank or a radiator, that is more challenging and will depend on a lot of other facts and circumstances. We are very interested in the contract to buy the transformer. What is the time period for performance? How much has been done on the transformer before the construction-start deadline. When will it be delivered? What outs does the sponsor have to follow through on the purchase? How real is the contract? We have not set any bright lines. We look at the totality of the deal and the information available and then make a determination once we know all the facts.

MR. MARTIN: Jack Cargas, same answer?

MR. CARGAS: We have been willing to rely on physical work on more than just transformers, but basically our approach is the same. We want detailed, time-stamped recordkeeping by a credible third party documenting the work that was done before the deadline. There is not any bright line.

MR. MARTIN: Does a single new nacelle work for either of you?

MR. HENDERSON: I don't think we have ever faced that question, so I don't have an answer, but it seems a little light.

MR. MARTIN: What other noteworthy trends do you see as we enter 2020?

MR. CARGAS: We see a major squeeze on human resources, especially in the fourth quarter of 2020. This past year was the heaviest year from that perspective ever, and it was almost intolerable. The squeeze is not only with respect to tax equity investors, but also sponsors and consultants like financial advisers, modelers, independent engineers, appraisers, lawyers — the list goes on and on.

MR. MARTIN: So get your deals done as early as possible this year. Yale Henderson, other noteworthy trends?

MR. HENDERSON: Offtake arrangements keep evolving and putting additional pressure on the cash flows from projects. There is less cash due to falling electricity prices. Projects with virtual power contracts or that sell into organized markets with hedges have electricity basis risk. This can reduce the cash flows further. We are spending a lot of time looking at how tightly projects are structured in terms of the ultimate ability to cover operating expenses given how low pricing has gotten to date. We are paying careful attention to project fundamentals.

MR. CARGAS: One other phenomenon that I don't think this market has seen before is the tax extenders bill in late December gave wind developers an incentive to rescind or cancel construction-start arrangements in 2019 and restart in 2020 to qualify for higher tax credits. There were media reports this morning referring to this as a "last-minute curve ball."

MR. MARTIN: Wind developers had to slam on the brakes. There was a lot of activity between December 17 and year end. While you were closing deals, the lawyers were doing what you described.

Let's move to bank debt and Ralph Cho at Investec. What was the volume of North American project finance bank debt in 2019 compared to 2018?

Bank Debt

MR. CHO: The preliminary data suggests that dollar volumes were down, but the number of transactions increased, suggesting a move from large gas-fired power plants and LNG terminals to renewables.

The dollar volume was down 15% in 2019 compared to 2018: $59 billion in 2019 compared to $69 billion in 2018.

The number of deals was up 58% to 306 transactions compared to 194 in 2018.

Renewables financings, which tend to be smaller, are dominating the flow.

Another interesting statistic is that if you zero in on power, bank volume was $36 billion in 2019 compared to $43 billion in 2018, so down 17%. This reflects again the move from thermal power to renewables.

MR. MARTIN: How many active banks were there in 2019 and how many do you expect in 2020?

MR. CHO: I like this question because I am very interested in new sources of capital. It is where I spend a lot of time. My estimate is we start the year with 80 to 100 lenders searching for deals, with 40 to 50 of them highly active. It is always interesting to see renewed appetite from institutions as markets are continuously adjusting. By and large lenders / continued page 6

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acknowledge receipt, but reserve the right to object once they learn more facts. They should remind the vendor that the delivery deadline was important to qualify for tax credits and tell it that they expect its help to provide whatever written evidence the US tax equity market and the Internal Revenue Service require for the developer to be allowed more time to receive the equipment or complete the project.

Tax equity volume is expected to reach $15 billion in 2020, up from $12 to $13 billion in 2019.

Developers should get deals done as early in 2020 as possible. Cranes, contractors, permission to tie up local roads, tax equity teams at banks, appraisers and other consultants and utility personnel needed for interconnection will be in increasingly short supply as the year wears on. Wood Mackenzie expects more than 15,000 megawatts of new and repowered wind projects to be installed this year, but says 9,000 megawatts are at risk of spillover due to bottlenecks.

THE TRUMP BUDGET delivered to Congress on February 10 would scale back tax incentives for renewable energy.

The proposals have no chance of clearing Congress this year. The document is a possible agenda if the president is re-elected and the Republicans retake control of the House and retain control of the Senate in November.

Each administration presents a budget in February for the fiscal year that starts on the following October 1. Congress has ultimate control over tax and spending decisions.

The president proposed in the latest budget to repeal the investment tax credit for projects on which construction starts after 2020. The investment tax credit is claimed currently on solar generating equipment, fuel cells, geothermal heat pumps and small combined heat and power facilities. Wind, biomass, landfill / continued page 7

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are expanding their definitions of what is an acceptable risk profile and what are acceptable economics. Of course, the majority of activity is always dominated by the top 20 banks just given their costs of capital and access to a broader range of borrowers.

The lender count includes grey-market institutions or non-bank lenders, and it also includes a lot of new South Korean institutions that have established a strong presence in our markets. If you combine this with the 15% drop in transaction volumes, you can see why you continue to hear the same broad theme of lender demand outpacing the supply of projects to finance. It has been hyper-competitive this year among lenders. It remains a great time to be a borrower. Pricing continues to tighten. In such a market, people come up with creative ways to increase leverage on deals.

MR. MARTIN: What is the current spread above LIBOR for bank debt, and to what does that translate as a coupon rate?

MR. CHO: It depends on the type of deal. Plain-vanilla loans are pricing at LIBOR plus 125 to 137.5 basis points. Short-term construction loans are pricing at LIBOR plus 75 basis points. We have been refinancing operating quasi-merchant gas deals at anywhere from LIBOR plus 225 to 275 basis points. Greenfield gas assets always get a little bit of a premium for the lender, so call it LIBOR plus 287.5 to 300.

It has also been interesting to watch the spread compression, or difference in pricing between Opco and Holdco loans. The excess demand to lend leads to tension among different classes of lenders, essentially forcing everyone to reevaluate the risk that each lender is willing to take and how much the lender is willing to compromise on yield just to get its capital put to work. What used to be a 200 to 250 basis-point spread differential is really compressed into 100 to 150 basis points for any lender who wants to be competitive.

There is also a growing pool of capital available from the stretch senior Holdco type of lenders that is creating a sweet spot at LIBOR plus 350 to 500 basis points based on the underlying risk. If you price something risky at that level, there is a ton of money that will jump in.

As far as the all-in coupon, the three-month LIBOR is about 180 basis points today. Last year at this time, it was 280 basis points, so it is down 100 basis points. Banks swap LIBOR, and LIBOR swaps are coming in around 175 to 200 basis points today. To get your coupon, just add the spread above LIBOR to that rate.

MR. MARTIN: Explain the difference between a Holdco loan and an Opco loan and is the spread compression you just described more relevant to the gas market than the renewable energy market?

MR. CHO: You can create Opco-Holdco loans on any asset. The Opco loan is basically a loan that is secured at the asset level. The Holdco loan is a loan higher up the ownership chain whose repayment is subordinated to the Opco loan.

MR. MARTIN: Correct me if I am wrong, but there is no yield premium currently for back-levered debt that sits behind tax equity in renewable energy deals: no yield premium compared to what the lender would charge if the loan were at the asset level.

MR. CHO: Correct. The back leverage is basically sitting upstairs, but there is really no loan at the asset level other than the tax equity. When we back lever renewables deals, the lenders do not put a premium on that. I am not sure this makes sense, but not only is there no premium, but the fact that the loan is back-levered also does not change the profile of how lenders are willing to size it. The Holdco loan in that context would be another loan that sits behind the back-levered debt.

MR. MARTIN: A few quick questions. Is there a LIBOR floor in the bank market currently?

MR. CHO: No. If there is a LIBOR floor, it is currently 0%.

MR. MARTIN: What are current debt service coverage ratios for wind, solar and quasi-merchant gas projects?

MR. CHO: Debt service coverage ratios for contracted wind farms are 1.35x for a P50 forecast. Solar is 1.25x for P50, given the lower standard deviation on resource forecasts. Solar output is more predictable. To be competitive in a typical gas-fired asset, the lender would have to be at around 1.3x to 1.35x over the life of the PPA. There is downward pressure on this because there a lots of banks that would love to be part of these types of deals. We do not see many PPA deals in the gas market. Holdco consolidated coverage ratios are as tight as 1.1x for sizing on debt service.

The other market segment is quasi-merchant gas. These deals are slightly more complicated. They are where most of the action on refinancings has been occurring. Lenders size at 1.15x revenue from the capacity price and revenue puts. If there is a heat-rate call option, sizing is based on a debt-service coverage ratio of 1.4x.

We have been assuming flat capacity forecasts in areas such as PJM and the New England ISO. We are seeing increasing use of cross commodity net-back hedges, which basically lock in a spark spread so long as commodity prices trade within a band.

We size loans based on this type of cash flow at 1.5x based on a conservative downside case. Sometimes we are open to giving credit on a conservative merchant energy revenue forecast. We would probably use a 2.0x to 2.5x debt service coverage ratio. The issue becomes what balloon repayment levels we are willing to accept at loan maturity. The answer varies by location, age and technology.

MR. MARTIN: So you will assign value to the merchant tail after the power contract ends for how many years at 2.0x to 2.5x?

MR. CHO: It depends on where the project is located and the age of the asset. We certainly do not want to go past the remaining useful life of the asset.

MR. MARTIN: Right, but you may go out to the reasonably expected useful life?

MR. CHO: We will probably want a cushion, and we are using conservative downside price forecasts.

MR. MARTIN: Some banks have been willing to accept only 8% rather than 10% sponsor equity. Where do you think the market is?

MR. CHO: No lender wants to lend on an asset where there is no equity value. The sponsor has to have skin in the game. That level sounds right, especially for renewables, but not so much for thermal assets. When it comes to renewables, there is clearly a halo effect where lenders are driven more by ESG and less by economics.

MR. MARTIN: So here is another phrase that will go into the annals of this industry. The earlier phrases were "wall of money," "satchels of Euros" and now "halo effect" for renewables.

Are there any other noteworthy trends in the bank market as we enter 2020?

MR. CHO: There are a lot of new trends, but I will just name a couple. Seoul, South Korea is a hotbed of capital, whether you are looking for senior debt, mezzanine debt, limited partner commitments, equity investments, every one of these types is available and open for business. It is a super-efficient source of capital. Capital is available in all sizes from small to large.

The delay potentially for another year of the PJM auctions of 2022 and 2023 capacity could sideline a slew greenfield gas-fired power projects that had been expected to come to market. However, the bank refinancing markets appear to remain open. About $2 billion in term loan refinancings are scheduled for closing over the next 30 to 45 days.

I expect continued capitalizations as borrowers take advantage of the different competing sources of capital I mentioned. It can go from A loan to B loan, B loan / *continued page 8*

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gas, incremental hydroelectric and run-of-the-river and ocean energy projects qualify for production tax credits instead of investment tax credits, but have a choice of claiming investment credits and foregoing production tax credits. The budget would leave production tax credits in place.

It would also repeal a residential solar credit for homeowners who install rooftop solar panels, solar hot water heaters and geothermal heat pumps after this year.

It would slow down depreciation on renewable energy facilities that are put in service after Congress acts on the proposal. Most such projects are depreciated currently over five years on a front-loaded basis. They would be depreciated instead over periods of from five to 20 years, depending on the "specific activity of the taxpayer and the type of property." No other details are provided.

The budget would require homeowners to pay taxes on any payments received from the local utility as a reward for taking energy savings measures. Utilities in some states offer rebates to homeowners as an incentive to install solar equipment, better windows, more efficient lighting and similar equipment. Section 136 of the US tax code spares residential customers from having to report payments from the local utility that are inducements to take measures "to reduce consumption of electricity or natural gas or to improve management of energy demand with respect to a dwelling unit." The section would be repealed.

Trump also proposed to repeal a tax credit of up to $7,500 for buying an electric vehicle. Credits could not be claimed on such vehicles put in service after this year. The credit phases out currently for any manufacturer's vehicles over a one-year period starting in the second quarter after the manufacturer has sold 200,000 vehicles. Tesla and General Motors have already reached this threshold.

This is not the first time that proposals to scale back renewable / *continued page 9*

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to A loan, and A loan to private placement, as capital moves from one pocket to another.

The last point is that structures in the renewable energy market will continue to evolve as a growing number of lenders accept merchant exposure. Lenders are always going to be looking for ways to drive higher-yield products.

Term Loan B

MR. MARTIN: Good list of trends. Let's move to Jean-Pierre Boudrias at Goldman Sachs. What was the term loan B volume in the North American power sector in 2019? How did that volume compare with 2018?

MR. BOUDRIAS: In 2019, we saw $4.6 billion of term loan B lending across the power sector. That means that the market was essentially flat from 2018 to 2019. Last year, about half of the volume was in the form of repricings. We did not see any repricing in our market last year, so volume remained flat versus 2018.

MR. MARTIN: How many transactions were there in 2019?

MR. BOUDRIAS: We saw 12.

MR. MARTIN: So the number of transactions was up if one focuses solely on new money. Last year, there were 18 transactions in total for $8.25 billion, but about half of that was repricings.

MR. BOUDRIAS: That's right.

MR. MARTIN: When should a CFO turn to the term loan B market rather than the bank market?

MR. BOUDRIAS: It is really a question of either wanting more leverage or looking to finance projects that will have more merchant exposure.

MR. MARTIN: You just heard Ralph Cho say that the banks are salivating over higher yields and looking for merchant exposure. Will that cut into the term loan B market this year?

MR. BOUDRIAS: The total B loan market is $300 billion in size. We have always been talking about a relatively small subsector of the market, so the market is unlikely to be significantly affected by what banks are willing to do. While banks can invest in the types of transactions that tend to seek financing in the term loan B market and in some cases they do, I do not see bank loans and B loans competing directly.

For example, the term loan B market has been a better conduit than the traditional bank market for acquisition financing just because of the efficiency and ability of some of the underwriting participants who underwrite transactions quickly and then distribute the paper efficiently.

MR. MARTIN: To be clear, the term loan B market is basically bank paper that is sold to institutional lenders. B loan deals are set up so that there will not have to be a lot of future interaction between the holders of the term loan and the borrower.

MR. BOUDRIAS: Correct.

MR. MARTIN: There is also a term loan C. What is it?

MR. BOUDRIAS: The phrase term loan C refers to things that should have been provided either in the form of letters of credit or bank guarantees. What market participants do is create a funded tranche that can be sold to the market with that tranche marketed to institutional investors rather than being provided by banks.

MR. MARTIN: One of the interesting stories last year was that bank rates were falling. There still seems to be downward pressure on interest rates as we head into 2020. Last year, term loan B pricing was moving in the opposite direction from the bank market. Rates were going up. What do you expect in 2020?

MR. BOUDRIAS: Last year was a tale of two markets. The relative attractiveness of the fixed-rate high-yield market relative to the leveraged loan market meant that the loan market on a relative basis was not super busy until probably November or December. Now we are in the midst of a wave of repricings of the kind we have not really seen since 2018.

MR. MARTIN: What volume do you expect this year?

MR. BOUDRIAS: My sense is if we are going to have repricings, we should be closer to what we saw in 2018, so closer to $8 to $10 billion compared to the $4.5 billion we saw last year.

MR. MARTIN: Pricing at this time last year for BB credits was around 350 to 375 basis points over LIBOR with a 1% floor and 1% OID. Single B credits were pricing at LIBOR plus 450 to 500 basis points. Where do you see pricing today as we start 2020?

MR. BOUDRIAS: It is difficult to go tighter than 350 to 375. That said, I am convinced that we will break into the 200-basis-point level at some point this year for BB credits. For single B, we are a lot tighter than we were last year. A new single B would issue in the 400 to 425 range today.

MR. MARTIN: So pricing is improving for borrowers. Are B loans still for seven years?

MR. BOUDRIAS: Yes.

MR. MARTIN: Advance rates in the B loan market have been in the mid-60% range. Has there been any change as we enter 2020?

MR. BOUDRIAS: There is no magic formula that solves for advance rates, but my guess is advance rates will remain 60% to 70%.

MR. MARTIN: How does a developer determine how much he can borrow in the B loan market?

MR. BOUDRIAS: It is similar to what Ralph Cho talked about for the bank market. B loans tend to be sized on what we call lender cases. We will assume certain merchant energy prices, assume capacity prices will remain flat or are declining and then look for enough cash available to pay down a portion of the debt over the life of the loan.

For example, targeting 50% of the loan to be repaid over seven years usually means, as a rule of thumb, that we will lend six to six and a half times EBITDA.

Eighty to 100 lenders are chasing deals, putting continuing downward pressure on interest rates.

MR. MARTIN: How large a transaction must one have to make it worth the trouble?

MR. BOUDRIAS: There is not as much liquidity for loans below $500 to $750 million, but with that said, debt as small as $225 to $250 million can be placed in the institutional market.

MR. MARTIN: Are there any other new trends in the B loan market as we enter 2020?

MR. BOUDRIAS: One of the biggest trends is the arrival of direct lenders. This started across the middle market and now it is spreading to larger transactions. Institutions are announcing transactions that they are handling on a sole basis that can be just shy of $1 billion. I talked about coming to the term loan B market for $225 to $250 million at a minimum. I would say that $125 to $200 million is a sweet spot for these direct lenders.

Some of these participants may be grey market lenders that Ralph Cho included in his count. It is something that we had not seen as much of before.

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energy tax credits have been sent to Congress. In the fall 2017, the House tax-writing committee, which was then under Republican control, voted to drop any inflation adjustment for production tax credits on electricity sold after November 2, 2017. The tax credits would have reverted to their 1992 level. The House committee bill would also have made it harder for renewable energy facilities to be considered under construction for tax purposes, and it would have repealed investment tax credits for solar and geothermal facilities that start construction after 2027. The proposals were not ultimately enacted, but they led tax equity investors to add protections in tax equity documents for future changes in tax law.

TAX CONTEST RIGHTS could be eviscerated if the US government wins a motion it filed in late January in the Alta Wind case.

The motion calls into question whether tax equity investors in sale-leaseback and inverted lease transactions can go to court to challenge any loss of tax benefits for which the investors are indemnified by the sponsor or protected by tax insurance.

Partnership flip transactions would also be affected where tax indemnities or insurance run to the partnership rather than to the tax equity investor directly.

Tax contest rights in some M&A transactions could also be affected.

Many renewable energy developers raise tax equity to finance projects. Tax equity is a form of capital that is returned to the investor partly in cash and partly in tax benefits. The sponsor must sometimes indemnify the tax equity investor if the tax benefits are less than expected.

The Alta Wind case involves six wind farms in California. Five of the wind farms were financed in sale-leasebacks. The sale-leasebacks occurred in 2010 and 2011. One project was sold to / continued page 11

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Project Bonds

MR. MARTIN: Let's move to project bonds then and John Anderson with Manulife.

Project bonds are long, cheap, fixed-rate money. The project bond market does not tend to do well when the bank and term loan B markets are wide open and looking for product. That seems to be the case this year. Interest in project bonds revives when people fear interest rates are headed up.

It did not seem like there would be much of a market at the start of 2019. Was there one last year?

MR. ANDERSON: The project bond market is a subset of the private placement debt market. It was pretty stable at about $100 billion in 2019. It was about a $100 billion the year before.

About 20% of the flow last year was infrastructure debt, the new term for project debt and public-private partnerships or PPPs.

Both the term loan B and project bond markets are open and are expected to do healthy volumes this year.

MR. MARTIN: Are these US or global numbers?

MR. ANDERSON: Project bonds that syndicated in US dollars. It includes some international projects.

MR. MARTIN: But mainly US projects?

MR. ANDERSON: That's right. It will be mainly US. We are doing about $12 billion a year of debt and infrastructure equity. That is about 60% in US dollars, 20% in Canadian dollars and 20% euro, sterling and Australian dollars. The dominant opportunity, whether it is in the US or Latin America, is US dollar flow. Even within that, Latin America is relatively small.

Of that, $20 billion was infrastructure. That is syndicated project finance debt. We know that there is a large amount of direct lending also occurring in smaller projects that does not come into the syndicated market. The size of the market is opportunity constrained rather than investor constrained.

To your point, we are the guys at project conferences with the badge that says, "Talk to me about long cheap money." We look for sponsors who want to lock in long-term base rates. They are looking at a community that will lend 30+ years against contracted cash flows. We give you a spread for life. It is the coupon throughout the life of the loan. There is no escalating spread in order to incentivize a refinancing that you see in some other markets.

We are seeing contracted power projects clear at spreads of about 175 to 190 over treasuries today. If 10-year treasuries are at 1.8% today, you are looking at coupons on project bonds in the 3.5% to 3.75% range.

The market is showing some willingness to look at partially merchant cash flows or clearing capacity markets. The market has evolved beyond the traditional utility PPA to more and more corporate PPAs.

Every flavor of project finance can be done here: wind, solar, biomass, geothermal, hydro. We saw some distributed generation deals done this year.

MR. MARTIN: How many active investors are there?

MR. ANDERSON: Since we are not a syndication agent, we do not track that as closely as some other people do. We talked a couple years ago about there being 25 active investors. I think the number is higher today because I don't see any life insurance companies that play in this market dropping out, and we are seeing European insurance companies becoming more interested in North America.

MR. MARTIN: How large a transaction does one need to make it worthwhile to borrow in the project bond market?

MR. ANDERSON: Syndicated transactions work best at $250 million and higher. If you come in below that, you are probably looking at doing something clubby in individual tickets of $25 to $50 million. A lot of our peers might do a smaller deal as a single-investor transaction. Thus, $25 to $50 million and up will work, but it just depends on how broad an investor base you want.

MR. MARTIN: How long does it take to close a project bond deal from start to finish?

MR. ANDERSON: It depends how fully baked it is. We have seen fully baked syndicated transactions make it to market in four to six weeks. The bond private placement market can move at least as quickly as, and sometimes more quickly than, the bank market. It takes longer where the transaction is not fully baked. Many lenders would be happy to work with you before all of your documents are done. Partly baked deals require a longer process. The key is to get a lead investor involved early as an anchor.

MR. MARTIN: Must a borrower be an investment-grade credit?

MR. ANDERSON: The market is deepest for investment-grade projects. The borrower need not be rated. It helps in a broad syndication, but project bonds can be placed without a rating if the lenders think the project is investment grade. The market will bid on BB senior-secured project finance paper. It is a sub-set of the broader market.

MR. MARTIN: What is the loan tenor? Is used to be a year short of the PPA term.

MR. ANDERSON: You can think of it essentially as the length of the PPA because project bonds are amortizing debt with stable debt service coverages throughout. By the time you get to the last year of the PPA, you are probably not putting a balloon payment at the end of the loan.

MR. MARTIN: Are there any new trends in the project bond market as we enter 2020?

MR. ANDERSON: We talked two years ago about the market turning away from coal in North America. We may be in the same position now internationally. We saw a few coal-fired projects get done in Asia over the last few years. Such projects have become much harder to do. There is strong demand for project bonds in the US. The ESG tailwind that Ralph Cho mentioned is definitely true in our space as well. If an insurance company finances a wind farm, the transaction goes up on its home page. People talk about it at the holiday party at the end of the year. There is a lot of feel-good around it among our employees.

Audience Questions

MR. MARTIN: Let's move now to audience questions. Ralph Cho, someone asked, "How do you define North America in your deal volume results: US, Canada and Mexico or just US and Canada?"

MR. CHO: US, Canada and Mexico.

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another wind developer in 2012. All of the projects had long-term 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.

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 the US government put in place in 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 tax equity investor in a sale-lease-back buys the project for its fair market value after construction and claims tax benefits on the project, but must first allocate the purchase price among the various assets that make up the project. Treasury cash grants were paid only on the share of purchase price allocated to the generating equipment as opposed to transmission assets, real estate, contracts and other intangibles.

The Alta investors assigned 93.1% to 96.9% of what they paid for the projects to the generating equipment. 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.

The taxpayers won in the trial court in 2016.

However, a US appeals court set the decision aside in 2018 and ordered a retrial. It instructed the trial court to appoint a different judge and to use a so-called section 1060 method for allocating the purchase price among the various assets. Under a

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MR. MARTIN: Here is a question for the tax-equity investors. "How is the tax-equity market dealing with the merchant portion of deals? How much merchant are you doing?"

MR. CARGAS: We are doing quasi-merchant wind and solar projects with hedges to put a floor under the electricity price. It would be difficult to do a fully merchant deal without a hedge. A few such transactions were done some years ago that have not performed terribly well.

MR. MARTIN: There are a number of questions about community solar. Ralph Cho, how interested is the bank market in lending to community solar projects?

MR. CHO: Community solar falls into the renewables category. There is appetite for it. Any well-structured, well-priced transaction will get a lot of traction. A limited number of banks have been looking at community solar deals, and I would throw other transactions like CCAs — community choice aggregators – and corporate PPAs that we have talked about offline, Keith, into the same bucket, but there is growing interest from banks in these types of transactions.

MR. MARTIN: Tax equity guys, people are asking, "What pricing is available for community solar?" I know you will not comment on pricing, but perhaps you can say something about your general willingness to do community solar.

MR. HENDERSON: Community solar is tougher for us to do. It does not have the volume that we are looking for, and the time and effort it takes to underwrite a community solar transaction is not very efficient from the standpoint of making best use of our people resources. Given the market volumes expected, particularly in wind, community solar could be a tough sell this year.

MR. MARTIN: Question for all three lenders: "Will credit cover insurance unlock new transactions for unrated or lower shadow-rated credits?"

MR. CHO: There is so much liquidity in the bank market that its role is fairly limited. No matter what level on the risk spectrum a project sits, there is a lender to fill that spot. How much does it is enhance the credit? It depends on the cost of that credit wrap and how much cheaper can I find a lender to lend at that level.

MR. ANDERSON: I agree. Most investors in the project bond market would rather underwrite and price the underlying risk and get paid for that. We would probably see the underlying project economics as more durable than the wrapping financial institution would since the underlying project economics have good forward visibility for 10, 15, 20 or 25 years. We saw in the global financial crisis that many of the credit enhancement agencies kind of went away.

MR. MARTIN: There are a lot of questions about energy storage. Let's start with Ralph Cho. "Are you financing standalone storage, and if so, what are the debt-service coverage ratios and debt equity ratios?"

MR. CHO: We are certainly open for business in financing energy storage. However, here is the issue with energy storage on a standalone basis. There are two storage models. A lender wants to see cash flows. If you give me very firm cash flows, the sizing coverages are going to be very tight and the pricing will be very tight.

On the flip side, we have also seen where the revenues are all over the place. It almost feels like we are being asked to take equity-type risks. If it looks like equity risk, it will not work in the bank market. If you can box the risk and show that the worst the project can do is X and the cash flows could go as high as Y, then maybe we can work with it. In deals with potentially volatile cash flows, the coverage ratio will be wider: call it 2.5x. We would have to get very comfortable with the underlying cash flows.

MR. MARTIN: One of you mentioned that tax equity structures are changing. The question is, "Could you please elaborate?"

MR. CARGAS: The days are gone when projects had 30-year PPAs with investment-grade investor-owned utilities. We have had to develop different ways of dealing with varying credits of offtakers for the electricity. There may be credit enhancements in some cases. There may be insurance. We have seen some fixed-flip transactions. There is so much more variety today in structures in place of what once was a commoditized structure.

MR. MARTIN: Next question. "Has BEAT" — the base-erosion and anti-abuse tax — "caused any fallout in the tax equity market?"

MR. CARGAS: It did a couple of years ago when a number of tax equity investors determined that they were subject to the tax. People exited the market. It was a problem for a number of sponsors.

I think many of those investors have remained out of the market, but one or two have determined that they are no longer subject to BEAT and have re-entered the market, which may be a positive for sponsors in this heavy-demand year.

MR. CHO: Keith, you know this subject better than we do, but my understanding is that the IRS guidance that came out on BEAT at the end of last year was fairly helpful for financial institutions and may have given some people who were concerned a little bit more breathing room. My sense is BEAT is not a significant issue currently in the market. ◎

Expanded Reviews of US In-Bound Investments

by Amanda Rosenberg, in Los Angeles

The US government will vet more foreign investments in US companies and assets starting February 13.

Foreigners taking controlling interests in US companies had to consider in the past whether to make a filing with the Committee on Foreign Investment in the United States — CFIUS, for short. The filings were voluntary, but failure to file could lead later to an order to unwind the investment. CFIUS is an inter-agency committee of 16 federal agencies that reviews foreign acquisitions for any national security issues. (For data on how often acquisitions run into issues in practice, see "CFIUS" in the December 2019 *NewsWire*.)

CFIUS now has broader authority to review acquisitions of non-controlling interests in US businesses, and certain filings are mandatory for acquisitions closing on or after February 13, 2020.

Legislation enacted in the summer 2018 called the Foreign Investment Risk Review Modernization Act (FIRRMA) expanded the committee's authority. However, many key changes to existing law did not become effective until final regulations were issued. The final regulations were released in January with a February 13 effective date.

Mandatory Filings

CFIUS will require mandatory filings in two scenarios.

The first is a transaction in which a foreign government acquires a "substantial interest" in US businesses involving critical technologies, critical infrastructure or sensitive data.

The foreign government will have a substantial interest in the business if a foreign company or investment fund has a 25% or greater voting interest, directly and indirectly, in the US business, and the foreign government owns at least a 49% voting interest in the foreign company or fund. If the foreign investment fund is a partnership, or the US business is a partnership, then only general partner or managing member interests count. The fact that a foreign government holds a substantial interest directly or indirectly as a limited partner will not bring mandatory filings into play.

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section 1060 method, the purchase price is allocated first to the hard assets up to their market values and what remains is considered purchase price for intangibles like the power contract, customer goodwill or going concern value. (For earlier coverage, see "Tax Basis Issues: Alta Wind" in the August 2018 *NewsWire* and "Treasury Loses Key Case" in the December 2016 *NewsWire*.)

The government asked the trial court in late January to dismiss the retrial on grounds that the court lacks "subject matter" jurisdiction to hear the case.

It argues that the tax equity investors have no standing to use the court's time since they are indemnified for any loss by the sponsor.

The sponsor responded in part that it is too late for the government to object on such grounds since the government has known of the indemnity for eight years through a full trial and appeal. The sponsor is expected to make other, substantive arguments in a brief in February.

Treasury cash grants were paid to the legal entity that owns the project with one exception. The owner in an inverted lease structure could choose to pass through the grant to the lessee. Sponsors often indemnified tax equity investors if the actual grant paid was less than expected.

There are three main tax equity structures in use today in the renewable energy market. In sale-leasebacks and inverted leases, the sponsor makes representations about the tax benefits. If any of these representations is untrue, then an indemnity must be paid. Representations are most common about whether the project was under construction in time to qualify for tax credits and about the tax basis used to calculate tax benefits. Tax insurance is sometimes purchased.

Representations may also be made in

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Certain foreign governments — called “excepted foreign states” — have been put on a “white list.” Investments by them do not trigger mandatory filings. Australia, Canada and the United Kingdom will be excepted foreign states until February 13, 2022 at which time the US will revisit the list. Other countries may be added at a later date if the US government is comfortable that the foreign government has adequate processes for analyzing foreign investments for national security risks and coordinates with the United States on investment security matters.

Mandatory filings also are required when foreigners acquire interests in businesses that make critical technologies for use in any one of 27 specific industries. The industries include nuclear power generation and manufacturing transformers, turbines or batteries. Filings have been mandatory for these types of investments under a pilot program that has been in place since the fall 2018.

In either scenario, the mandatory filing is a short-form declaration that requires less information and has a shorter review period than a regular filing.

Certain investments are exempted from the mandatory filing requirement, including investments by funds that are controlled and managed by US nationals and investments by certain “excepted investors.”

An excepted investor is an investor with strong ties to an excepted foreign state. Such an investor must jump through many hoops, so the bar to qualify as an excepted investor is high.

The US government will vet more foreign investments in US businesses and assets starting February 13.

Non-Controlling Interests

FIRRMA gave CFIUS authority to review non-controlling interests in a new class of “covered investments” in companies dealing with critical technologies, critical infrastructure and sensitive personal data.

Covered investments by excepted investors are not subject to CFIUS review.

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

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

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

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

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

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

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

Real Estate

FIRRMA expanded the CFIUS authority to review certain real estate transactions. The final regulations implement that authority.

A bare acquisition of real estate was not subject to CFIUS review in the past because it did not involve the acquisition of a US business. Now, CFIUS may review the purchase or lease of "covered real estate" by a foreign person if the transaction provides the foreign person three out of the four following rights: the right to physical access, the right to exclude others from access, the right to improve or develop the site or the right to affix structures or objects to the site.

However, not all sites are "covered real estate." The site must be part of an airport or seaport or be near certain military installations or other sensitive US government facilities. The final regulations include a list of military and sensitive sites. Different sites have different standards for determining whether land is near enough to fall within CFIUS jurisdiction. CFIUS plans to publish a web-based tool that will help parties understand the geographic coverage of its expanded jurisdiction over real estate transactions.

Certain investors from Canada, Australia and the United Kingdom are "excepted real estate investors" and do not have to vet site purchases or leases.

Filings related to real estate investments remain voluntary. All real estate transactions — whether or not they involve "covered real estate" or an "excepted real estate investor" — remain potentially of interest to CFIUS under its broad authority to review acquisitions of controlling interests in US businesses by foreigners.

Other Changes

The mandatory filings and need to vet acquisitions of non-controlling interests do not apply to any / continued page 16

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partnership flip structures, although the representations and indemnity obligation may run to the tax equity investor directly or from the sponsor to the tax equity partnership with the partnership then distributing the indemnity to the tax equity partner.

The sponsor has contest rights before it is required to pay an indemnity. In sale-leasebacks and inverted leases, it can require the tax equity investor to challenge any IRS disallowance. In partnership flip deals, any IRS audit should be at the partnership level. The sponsor is usually the partnership representative for dealing with tax audits and can cause the partnership to contest directly.

If the US Court of Federal Claims dismisses the Alta retrial, it could place a cloud over the ability to challenge IRS disallowances of tax benefits in tax equity deals in court.

Many M&A transactions could also be affected where the seller makes tax representations and can require the buyer to contest any IRS disallowance before the seller must pay an indemnity.

The issue will be how much weight to put in a ruling by a single court.

UNPREDICTABLE TARIFFS remain a threat to project economics.

President Trump issued a proclamation on January 24 imposing import tariffs on products made from steel or aluminum where the metals account for at least two thirds of the product value. The tariffs are 25% for steel and 10% for aluminum. They will apply to products made from steel or aluminum that enter the US or are removed from bonded warehouses after February 7, 2020.

The tariffs will apply only to a short list of products that the government published in the *Federal Register* on January 29.

Wind turbines are 71% to 79% steel, but are not on the list.

It is unclear whether the lists will be updated. The proclama- / continued page 17

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transaction that closes or is significantly advanced before February 13, 2020.

A transaction is considered significantly advanced if the parties signed a binding written agreement establishing the material terms of the transaction or an investor has made a public offer to shareholders to buy shares of a US business.

In cases where filings are only voluntary, they will be easier to do in the future. Short-form declarations will be accepted starting on February 13. Such declarations are subject to a 30-day review period rather than the 45-day review period for a full notice that a foreign company might file voluntarily. Any filing must be made by both the buyer and the seller in an acquisition.

Whether it makes sense to file a short-form declaration in place of a full filing depends on the complexity of the investment, the identity of the acquirer and the sensitivity of the assets. The abbreviated declaration is expected to streamline the CFIUS process for investors making investments that carry low risk of national security concerns. ◎

Lending To Hedged Wind and Solar Projects

by Christine Brozynski and Connie Gao, in New York

Quasi-merchant projects that sell into the spot electricity market and use hedges to put a floor under the electricity price are becoming more common, particularly in ERCOT where power purchase agreements remain scarce.

Lenders financing these projects should be aware of how cash flows will be affected as well as of other risks inherent in these structures.

Common Hedges

One of the most common forms of hedge in ERCOT (where most of the renewables hedges in the United States are concentrated) is a physical fixed-volume hedge.

Under this type of hedge, the project company sells all of its electricity into the grid for the spot price at a grid “node” and keeps the revenue.

At the same time, it enters into a hedge that requires the project company to purchase a fixed volume of power at the “hub” each hour for the hub price and immediately re-sell that hub power to the hedge provider for the contract price under the hedge.

The fixed volume of power is set when the hedge is signed and is not adjusted based on actual production at the project. The contract price is a fixed price per megawatt hour. The project company uses the merchant revenues received from its sales of electricity at spot prices to buy the electricity at the hub that will be sold to the hedge provider.

Fixed-volume hedges can also be financial instruments rather than physical transactions. This type of hedge is more common outside ERCOT. Physical hedging means that power is actually sold to the hedge provider as part of the transaction, while financial hedging means the parties settle financially with respect to a notional quantity of power determined when the hedge is put in place.

The main difference between the two hedges is the payments.

Under physical hedges, the project company must spend money each hour to purchase power at the hub. The hedge provider then purchases that power from the project company, paying the contract price for that power usually on a daily basis (although sometimes these payments are only made monthly).

Financial hedges, on the other hand, are usually structured as contracts for differences. The hedge settles financially each month on a fixed notional quantity of electricity that varies for each hour. The floating hub price is multiplied by the notional quantity of power for each hour. That amount across all hours in a settlement period is called the "floating amount." The fixed price in the hedge contract (also called the strike price) multiplied by the notional quantity of power required in a settlement period is called the "fixed amount." The floating amount and fixed amount are netted against each other at the end of each month. If the fixed amount is higher, the hedge provider pays the project company the difference. If the floating amount is higher, the project company pays the difference to the hedge provider.

Another common type of hedge is a proxy revenue swap. It is settled financially at the end of each quarter.

There are two main differences between proxy revenue swaps and financial fixed-volume hedges.

The first is that the fixed price in a proxy revenue swap is a lump sum per quarter (the "fixed payment"), unlike fixed-volume hedges, in which the contract price or fixed price is a fixed charge per megawatt hour.

The second difference is that the floating amount is not based on a schedule of fixed volumes attached to the hedge at the time of hedge execution; rather, it is based on the "proxy generation" from a project. For wind proxy revenue swaps, proxy generation is the actual electricity produced by the project, adjusted to assume fixed operational inefficiencies for each turbine.

The calculation is similar in solar proxy revenue swaps, although sometimes a time series is used to calculate production instead of measuring actual production from the project.

The assumptions about operational inefficiencies are determined when the proxy revenue swap is signed.

The proxy generation is multiplied by the hub price for each hour to calculate the "proxy revenue" for the settlement period. The proxy revenue is netted against the fixed payment. If the proxy revenue is higher, the project company pays the difference to the hedge provider. If the fixed payment is higher, the hedge provider pays the difference to the project company.

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tion said the government is focused on so-called derivative products made from steel and aluminum that have three features in common. First, the metals account for at least two thirds of the product value. Second, import volumes increased year to year after June 1, 2018 compared to the two years before. Third, the import volumes after June 1, 2018 are up by more than 4%, which is the average increase in all US imports during the same period.

Products imported from Argentina, Australia, Canada, Mexico — and, in the case of steel products only — Brazil and South Korea will not be affected.

Trump said he imposed the additional tariffs because domestic steel and aluminum mills are still not operating at least at 80% capacity, a level he says is needed to ensure US national security.

Separately, the administration is moving to impose anti-dumping and countervailing duties on wind towers imported from Canada, Indonesia, Korea and Vietnam. The US Commerce Department found in January that towers from the four countries are being dumped at discounts below market of 5.04%, 6.38%, 5.98% and 65.96%, respectively. This is on top of countervailing duties of 1.09% to 20.29% that it recommended be collected on wind towers from Canada, Indonesia and Vietnam. A coalition of US wind tower manufacturers had wanted dumping duties of 422% for Korea and 109% for Vietnam.

These are preliminary duties. The Commerce Department hopes to issue the final duties on April 20 for Vietnam and on June 25 for the other three countries.

The focus shifts next to the US International Trade Commission, which must find that US producers have been injured or are threatened with injury from illegally traded imports. Importers are required in the meantime to deposit the preliminary duties or post bonds.

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Hedges

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Cash Flow Risks

Lenders focus on several issues when financing hedged projects.

The first issue is the risk to cash flow caused by differences between the hedge payments and merchant revenue.

This can be sub-divided into three main risks when the hedge is a fixed-volume swap: basis risk, volume and shape risk and covariance risk.

Basis risk is the risk that the hub price will be higher than the nodal price where the power is sold, so that it costs more to buy electricity to resell to the hedge provider than what the project was paid for the electricity it sold into the grid.

Volume risk and shape risk is the risk that the project will produce less electricity than it is required to buy at the hub (volume risk) and that the periods of high and low output do not align in terms of timing with the high and low fixed volumes under the hedge (shape risk).

Lenders financing hedged projects that sell into the spot market should focus on three main risks that will cause cash flows to fluctuate.

Covariance risk is the risk that the spot price for power will be depressed if all of the wind farms or solar facilities in a given area produce at the same time, assuming there is a high enough concentration of wind farms or solar facilities in the area.

Basis risk is also an issue for projects with proxy revenue swaps, but volume risk, shape risk and covariance risk do not come into play. The project company will receive a fixed lump-sum amount under the proxy revenue swap no matter how much electricity the project generates. The project company retains operational risk in the sense that a mismatch is possible between actual efficiency of the turbines and the efficiency of the turbines assumed to set the fixed payment when the swap was put in place.

Lenders should try to capture the complexity of these hedges in the model.

For fixed-volume hedges, it is not enough to assume in the model that the project will receive the fixed price for P99 volumes and then bank all revenues for production in excess of P99. Even after accounting for basis risk, the issues surrounding volume and shape risk and covariance risk can result in less revenue than anticipated. A white paper by REsurety, Inc. and EnergyGPS Consulting, LLC, called "The 'P99 Hedge' That Wasn't," analyzes historical data in ERCOT to find that hedge revenues were arguably overestimated by an average of 18%, while volumes produced in excess of the fixed-volume requirements under the hedge proved to be 38% less valuable than the average market price of energy during the same period.

Despite the potentially uneven cash flows, debt-service coverage ratios traditionally are no higher for hedged projects than for projects with utility power purchase agreements.

Mitigating Risks

One way for lenders to manage basis risk is by implementing mandatory prepayment triggers.

The triggers can take various forms.

One such trigger for which the lenders could require a prepayment is where the average nodal price received by the project company over a predetermined rolling period of time drops below a threshold agreed to by the lender and the project company. Another type of trigger that could trigger a prepayment is where the average differential between the hub price and the nodal price (the "basis differential") exceeds a pre-agreed threshold.

The mandatory prepayment itself can also be structured in different ways.

One is as a sweep of a percentage of cash on deposit in a revenue account in the waterfall. Another is a fixed payment. Lastly, lenders can also recalculate projected debt-service coverage ratios for the remainder of the term based on an updated market report. The prepayment would be in the amount required for the project company to meet a required minimum debt-service coverage ratio going forward.

Basis risk is often partially mitigated by a tracking account in a hedge.

A tracking account is essentially a working capital loan from the hedge provider to the project company in the amount of the difference between, on the one hand, the amount the project company owed under the hedge for that month and, on the other hand, the merchant revenue received by the project company for power for that month. The tracking account is capped at an amount negotiated by the parties, called the tracking account limit.

Lenders can require a separate mandatory prepayment if the outstanding tracking account balance reaches a certain threshold.

This prepayment can be structured as a one-time fixed amount paid by the project company or as a cash sweep at the appropriate place in the waterfall. The project company may negotiate for the right to hold the prepayment amount in a reserve account for a number of months to give it a chance to pay down the tracking account and cure the prepayment trigger event.

Reserve accounts can also be used to mitigate basis risk independently of the tracking account.

One approach is to require the project company or other borrower under the term loan to establish a reserve at term conversion to be used for working capital as a buffer against potential cash flow issues. If a tax equity investor is already requiring this under the tax equity documents, the lenders may take comfort in the existence of such a reserve instead of requiring a separate one under the loan documents.

Lenders could require springing reserves that must be filled upon a trigger event. A borrower may negotiate an automatic waiver of a springing reserve requirement if the historical and forward-looking debt-service coverage ratios exceed the minimum requirement by a pre-negotiated margin.

When evaluating potential cash-flow issues, another item lenders should look out for in a hedge is a distribution block. Hedge providers whose interests are secured by a lien on the project sometimes prohibit the project / *continued page 20*

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Meanwhile, US solar developers are waiting for the results of a mid-term review of a "safeguard" duty that the Trump administration imposed on imported solar panels in February 2018. The duties are currently scheduled to remain in place for four years and to fall from 30% to 15% by the last year of the four-year period. They have been declining by 5% a year.

Suniva, one of two panel manufacturers that asked for the original duties to bolster US manufacturing operations, asked to slow the rate of decrease to 1% a year.

Rhonda Schmidtlein, a Democratic member of the US International Trade Commission, said at a December 5 hearing on the tariffs that "I think technically if the president wanted to he could extend the safeguard beyond 2021."

The commission released a 488-page mid-term review on February 7, but without making any recommendations. The report is a survey of how the tariffs have affected US solar cell and module manufacturers.

The US Trade Representative is moving at the same time to revoke a tariff exemption for imported bi-facial solar panels. The trade representative granted the exemption in June 2019 and then withdrew it four months later, but a federal court blocked it from withdrawing the exemption until it followed proper procedures. (For earlier coverage, see "Solar and Wind Tariffs" in the December 2019 *NewsWire*.) The US Trade Representative put a request for comments in the *Federal Register* on the January 27, starting a 60-day clock to run on comment submissions. Soon after, the government is expected to withdraw the exemption again.

Finally, a draft executive order is reportedly circulating within the Trump administration to pull the United States from a 48-country Government Procurement Agreement. The GPA treaty allows companies in countries that / *continued page 21*

Hedges

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company from making distributions after an event of default or termination event under the hedge. Allowances are not typically made for debt service or preferred distributions to tax equity.

Interparty and Collateral Risks

Project companies entering into hedges are required to post credit support.

There are important differences among the various forms of hedges in use in the market.

This may take the form of a letter of credit or cash. Alternatively, the project company may grant the hedge provider a first lien on the project company assets and the equity interests in the project company. For projects with construction financed by debt, the lien to the hedge provider is usually granted at commercial operation after the debt converts to back leverage. This is because construction is usually financed 90% with debt, if not more; in the event of a foreclosure, there would not be enough cushion to repay both the lender and the hedge provider if both were to share collateral.

The typical hedge contains a list of conditions precedent for the first lien to take effect and to reach commercial operation under the hedge.

Lenders should make commercial operation and the grant of the first lien conditions precedent to term conversion in the loan documents. They should also do careful diligence of the list of conditions precedent to ensure that the hedge provider does not have any "outs," similar to the way a lender might review a list of conditions precedent to the tax equity funding. Ideally each condition precedent should be as objective as possible rather than in the discretion of the hedge provider. Lenders should also ask for forms of any certificates or opinions that must be delivered to the hedge provider at commercial operation to be attached to the hedge at hedge execution. This reduces the risk of potential delays or deadlock when the project is gearing up for commercial operation.

Consents to collateral assignment of the hedge often differ slightly from customary consents to collateral assignment given by third parties.

While lenders are usually granted a cure period for defaults, it is not uncommon for hedge providers to require the lenders to post collateral after part of the cure period has lapsed if the default remains uncured. The collateral amount is usually the difference between the hedge provider's exposure and the collateral already posted. The collateral amount is adjusted up or down during the cure period as the hedge provider's exposure fluctuates. If the default remains uncured at the end of cure period provided in the consent, then the hedge provider is allowed to draw on the collateral.

Lastly, hedge providers sometimes make the project company make representations or covenants in the hedge, particularly if the hedge provider has a lien. For example, a secured hedge provider might include representations and covenants about the security interest and preservation of the collateral. A common covenant requires the project company to operate the project in accordance with prudent operator practices or a similar standard of care. Lenders should review any covenants to ensure that the project company can satisfy all the obligations. ◎

Colombia: Opportunities and Challenges

by Monica Borda-Olarte, Pablo Calderon and Rachel Rosenfeld, in Washington

Colombia is expected launch a third renewable energy auction in 2020.

Participation in the last two auctions was less robust than hoped due to an inflexible regulatory framework and the amount of security required by bidders.

Colombia awarded contracts for wind and solar projects worth about $2.2 billion in the second auction in October. Roughly 150 companies submitted bids.

Seven electricity generators secured 15-year power purchase agreements for 1,298.9 megawatts of new wind and solar capacity spread among eight projects (five for wind and three for solar) with a weighted average price of $28.09 a megawatt hour. This weighted average is about $14.68 per megawatt hour below the current prices in bilateral contracts between energy traders and generators. By comparison, Mexico's third round of renewable energy auctions in 2017 netted an average price of $20.57 a megawatt hour.

Twenty-two companies will buy electricity under the contracts. The offtakers include Celsia, Enel, Empresas Públicas de Medellín, and Ecopetrol, as well as smaller local power distributors like Electrificadora del Caribe and Electrificadora de Santander.

Details of the seven generators are shown in the chart on the following page.

The second-round auction in October followed a failed attempt to hold an initial auction in February 2019. No bids were accepted in the initial auction because the offers received did not meet the criteria set by the Energy and Gas Regulation Commission (*Comisión de Regulación de Energía y Gas* – CREG) for ensuring market competition.

Historically, the renewable energy market in Colombia has been negligible compared to Colombia's hydroelectric and thermal generation. Hydroelectric generation has been well-developed due to high rainfall levels and natural resources, and thermal energy has been used to fill in generation gaps during dry periods. However, it is estimated

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are parties to the agreement to bid to supply goods and services in each other's government procurements. The Government Accountability Office, an arm of the US Congress, said in a 2017 report that the US has allowed other countries to bid on about $837 billion in procurement contracts, while the next five largest signatories – the European Union, Japan, South Korea, Norway and Canada – have opened only $381 billion to outside bids.

THE US REVERSED COURSE and increased tax credits for new wind projects that start construction in 2020 compared to 2019.

Some developers then slammed on the brakes and spent the last 10 days of 2019 rescinding or cancelling arrangements they made to start construction in 2019.

A tax extenders bill that cleared Congress on December 20 gave wind developers another year through the end of 2020 to start construction of new projects to qualify for federal tax credits. Wind projects that start construction in 2020 will qualify for tax credits at 60% of the full rate compared to only 40% if construction started in 2019.

Under a rescission doctrine in US tax law, a contract is ignored if it is unwound in the same tax year it was signed in a manner that restores the parties to their original economic positions as if no contract was signed. Whether cancelling contracts in the next year works to undo 2019 efforts depends on how construction started. It is hard to see how costs can have been incurred in 2019 if the money was refunded or the equipment was never delivered. It is harder to undo physical work at a project site. However, physical work at a factory may be possible to undo, depending on the facts, if the contract is cancelled, the work stopped, damages paid and the work is kept by the manufacturer.

The same tax

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that large-scale onshore wind and geothermal would be able to achieve the same cost per kilowatt hour as current hydroelectric generation, further diversifying the country's energy mix and increasing overall installed capacity (which is currently around 17,300 megawatts).

In 2022, non-hydroelectric renewable energy sources will represent 11% of Colombia's energy matrix, according to the government.

Opportunity Knocks

Colombia has a series of regulatory, tax, geographic, political and macroeconomic advantages, making it an attractive place to invest in renewable energy projects.

It issued regulations in 2018 for distributed solar generation (up to 100 KW) and other renewable distributed generation (between 100 KW and 1 MW).

Colombia has implemented approximately 34 legal and regulatory reforms since 2006, many of which promote investments in renewable energy. Government regulations allow commercial, residential and small industrial consumers to produce energy to satisfy their own needs and to sell any surplus to the interconnected system.

A key component of the legal and regulatory incentives offered to promote investments in renewable energy are the tax incentives for investors. There are two main tax incentives. VAT taxes are waived for renewable energy goods like solar panels and for domestic or imported renewable energy services. Income-tax deductions may be taken over 15 years for up to 50% of investments made in projects using non-hydroelectric energy sources to generate electricity.

Taxpayers reporting tax on income directly derived from new spending on research, development and investment for the production and use of energy from renewable sources or efficient management of renewable energy are able to deduct up to 50% of the value of such investments. The maximum value to be deducted in a period not exceeding 15 years counted from the fiscal year following that in which the investment is made is fixed at 50% of the total value of the investment made. The maximum value to be deducted for each fiscal year may not exceed 50% of the taxpayer's net income, before subtracting the income tax deduction.

Accelerated depreciation is also allowed on the share of asset value used to generate renewable energy, not exceeding 20% of the asset value per year. This tax incentive applies to renewable energy generators making new investments in machinery or equipment or paying for civil works acquired or built after the law was enacted in 2014.

Customs duties and tariffs do not have to be paid on machinery, equipment, materials and supplies imported for exclusive use in renewable energy projects.

There are also special incentives for battery energy storage.

Colombia has a daily average solar irradiation of 4.5 kilowatt hours per square meter, exceeding the world average of 3.9 kilowatt hours per square meter. One of the world's renewable energy champions, Germany, has irradiation of 3.0 kilowatt hours per square meter.

Various studies have found that the wind energy potential is sufficient by itself to meet the country's current energy needs. The department of La Guajira stands out for its high wind resources (estimated at 21,000 megawatts of capacity). Winds in La Guajira have been classified as class 7 (close to 10 meters per second annual average), making it one of only two regions in Latin America with winds of this speed.

The Colombian government aims to reach about 1,400 megawatts of installed capacity in non-hydroelectric renewable energy by 2023. This is 28 times more installed capacity than the current capacity, mostly coming from new solar and wind projects in the north of the country in the La Guajira and Cesar regions.

In recent years, Colombia's GDP grew above the average for Latin America and the Caribbean. While in 2017, the country's economy

Sponsors	Type	Project	Capacity (MW)	PPA price (¢/KWh)
AES Gener	Wind	Casa Eléctrica	180	29.1
EDP Renováveis	Wind	Alpha	212	26.3
EDP Renováveis	Wind	Beta	280	27.9
Celsia	Wind	Acacia	80	30.3
Celsia	Wind	Camelias	250	30.9
Trina Solar	Solar	San Felipe	90	29.5
Trina Solar	Solar	Cartago	99	27.9
Trina Solar	Solar	El Campano	107	29.7

grew at a 1.8% rate, faster than the 1.3% rate for the region as a whole. During the period 2010 through 2017, the Colombian economy grew at an average annual rate of 3.8%. The country's GDP growth was 2.6% in 2018. The GDP is estimated to have grown by 3.1% in 2019, making Colombia one of Latin-America's top 3 fastest growing economies.

Colombia is expected to put more renewable energy power contracts out for bid in 2020.

In the not-too-distant past, Colombia was seen as a state on the brink of failure. Colombia's sovereign debt was granted investment grade status by Standard & Poor's, Moody's and Fitch in 2011. In 2014, Moody's raised the country's rating from Baa3 to Baa2. In March 2017, Fitch Ratings improved Colombia's rating outlook: it went from negative to stable. The country was invited in 2018 to become a member of the OECD. The only other OECD countries in Latin America are Chile and Mexico. Colombia signed an accession agreement in May 2018 and is on track to join soon.

Colombia is working actively to tackle climate change. It wants to increase its installed generating capacity from renewable energy by 50 times, from less than 50 megawatts in 2018 to 2,500 megawatts in 2022. It wants to reduce the country's output of CO2 by nine million tons. It wants to increase non-hydroelectric renewable energy from less than 1% to between 8% and 10%.

Three other areas of focus in the coming years are efficient management of demand, intelligent metering and energy storage. The government is encouraging private-sector players to reinvent themselves to take advantage of new business opportunities in decarbonization, digitization, and decentralization.

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extenders bill retroactively extended super-accelerated depreciation for projects on Indian reservations. Such projects qualify if put in service by the end of 2020. The deadline had been 2017. Equipment that is normally depreciated over five years on a 200% declining-balance method would be depreciated over three years instead.

Geothermal, biomass, landfill gas, trash, incremental hydroelectric and run-of-the-river and ocean energy power projects have been given more time to start construction to qualify for federal tax credits. They will qualify if they are under construction for tax purposes by the end of this year.

EIGHT TAX EQUITY INVESTORS in the DC Solar deals filed suit in December against the law firms that wrote opinions as well as the accounting firms, appraisers and brokers involved in them.

DC Solar was a high-flying manufacturer of mobile solar platforms that can be used to light outdoor sporting events, construction sites and similar venues. The company claimed to have leased as many as 17,000 units to end users. It raised hundreds of millions of dollars of tax equity. The FBI raided the company in December 2018 after concluding, based on information from a former employee, that only a fraction of the units were real.

Jeff and Paulette Carpoff, the founders of the company, pled guilty in late January to operating a massive Ponzi scheme. Four other employees had already pled guilty.

The Carpoffs led a lavish lifestyle, owning 149 cars, a minor league baseball team and as many as 20 properties, including in Lake Tahoe, Las Vegas and the Caribbean. The rapper Pitbull entertained at the company Christmas party in 2018.

The IRS disallowed the tax benefits claimed in some of the / continued page 25

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Second Auction

The government made several improvements in the second auction that helped to increase the number of bidders and to maximize diversification.

The power contract term was increased from 12 to 15 years starting on January 1, 2022. The deadline to reach commercial operation was extended. The minimum generating capacity was decreased from 10 megawatts to five megawatts.

The new PPA provides developers with flexibility to outsource energy from third parties in the event construction of a developer's project is delayed. Power suppliers were allowed to submit offers in different power blocks. (For an earlier discussion about bankability of the PPA, see "Bankability of Colombian Projects" in the October 2019 *NewsWire*.)

The newly awarded clean energy suppliers will mobilize an estimated $1.3 billion in investment, boost Colombia's generating capacity by 2,250 megawatts, and attract another $2 billion of estimated private-sector investment.

The second auction was supported by the US Agency for International Development through workshops, hosting events for potential bidders, an auction IT platform, and a bilingual document library with rules for bidder participation and the contracts to be awarded to winning bidders, among other resources.

Future Auctions

The government is expected to hold a third renewable energy auction in 2020, but it recognizes that various challenges remain.

A major hurdle to increasing renewable energy production is the lack of infrastructure in non-interconnected areas. Bidders in future auctions should assume their projects will have to include grid infrastructure as well as storage.

Notwithstanding criticism from foreign investors in response to the initial auction, the PPAs awarded in the second auction still set the energy prices in Colombian pesos, and payments will be made in pesos at a price that will be adjusted on a monthly basis. This remains a major challenge for foreign investors due to Colombian peso volatility and currency risk. Investors have to use financial instruments, such as currency swaps, to hedge against this type of currency risk.

Various developers complain that there has been a lack of planning around community engagement in areas where projects are to be located, and that conditions placed on bidders with respect to coordination with communities were overly burdensome and complicated.

In the past, mining and oil projects in the region have been brought to a halt by local protests based on environmental, social and indigenous land rights concerns related to the local community and nearby natural resources affected by construction and operation. Such confrontations are costly and many potential bidders are deterred by the potential reputation risk from such protests. ◎

Reading the Market

Many market participants gather at the Infocast Projects & Money conference in New Orleans each January to get a read on what to expect in the year ahead. A group of investors and the CEO of one of the most successful independent power companies had a wide-ranging discussion about the state of the market and where they see opportunities. The panelists are Paul Segal, CEO of LS Power, Himanshu Saxena, CEO of the Starwood Energy Group, Bruce MacLennan, a partner in Global Infrastructure Partners, and Steve Petricone, a managing director at Fortress Investment Group. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Evolving Market

MR. MARTIN: Herb Magid from Ares said two years ago on this panel that the market feels like someone has taken what we knew and thrown it against a wall. That makes it both a challenging time and also a nervous time for investors. Paul Segal, two years on, has the picture become clearer?

MR. SEGAL: I don't think so. The industry is still in a state of rapid change. We continue to see outside ERCOT flat-to-falling demand for electricity. We have incredibly cheap gas. There is a real dedication toward renewables and moving to a cleaner power grid in the future, driven in many cases by state action. We can continue to expect basically zero-cost energy to flood the grid.

MR. MARTIN: Zero cost, not so much nuclear at this point, which was supposed to be too cheap to meter. In this case what is cheap is solar and wind.

MR. SEGAL: Solar and wind, and that forces firms like us to re-evaluate continuously where to go, not remain stagnant, not stick with one particular strategy.

MR. MARTIN: So maybe the picture is a little clearer. Everything is moving toward renewables.

MR. SEGAL: Broadly speaking that's right.

MR. MARTIN: Himanshu Saxena, clearer picture today or is it still as if what we knew has been thrown against a wall and bounced off in pieces?

MR. SAXENA: I think that in the last five years, we had expected certain markets to break. California was one of those markets that we knew was going to break; we just didn't know when that would happen. This year, you start to see capacity pricing in California at six times what it was last year. You could buy a CCGT in California for $70 a kilowatt / continued page 26

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tax equity transactions. In one suit filed in the US Tax Court about a tax equity deal structured as a partnership flip transaction, the court papers said the parties claimed tax bases of $150,000 per mobile platform that the IRS asserted cost $17,000 each to build. (For more details, see "Solar Transactions Land in Court" in the October 2018 *NewsWire*.)

The eight tax equity investors who filed suit said they invested at least $862 million in the deals. At least one other tax equity investor who did not join the suit is reported to have invested another $340 million.

The suit charges the consultants and brokers "either knew of or were willfully blind to red flags and indicators of fraud" and that they "concealed and failed to disclose . . . material information about DC Solar that would have caused [the tax equity investors] not to invest . . . ."

There are lessons for both consultants and investors. One lesson is someone should visit the site to make sure a project is real. Do basic diligence about the sponsor. Be attuned to warning signs. Law and accounting firms should think carefully about writing opinions on aggressive deal structures or facts. Investors should recognize that they are taking risks if they are earning premium returns and all they can get is a more-likely-than-not opinion about key aspects of the transaction.

Separately, lawsuits continue to be filed in connection with failed landfill gas partnerships in which a Chicago law firm acted for 34 clients, including 20 National Football League players.

The latest is a suit in federal district court in south Florida filed by former Miami Dolphin star Zach Thomas in an effort to get the US government to refund $18,600 in penalties that Thomas and his wife had to / continued page 27

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two years ago and now it is worth multiples of that. The same thing is happening in Texas. For years, there was no price signal in Texas to build new capacity. Last year, summer pricing in Texas was $150 to $170 a megawatt hour.

So we see these markets are starting to break. California and Texas are examples. We see similar things in New York. There is a point in time where renewables become too large a share of the market, and failure to do a proper redesign of the market leads inevitably to markets breaking. So we think MISO will follow the same trajectory.

MR. MARTIN: What does it mean for a market to break? What market design is needed?

MR. SAXENA: Markets have to compensate dispatchable resources properly for the reliability and capacity value they provide. These resources cannot just be free insurance for the markets. If the markets do not pay for this insurance, these dispatchable assets will shut down, thereby hurting the reliability of supply.

MR. MARTIN: What do you foresee for MISO?

MR. SAXENA: Coal retirements will create reliability issues in MISO. There will be pockets of opportunity for new development. Renewables are the future, but that future is not in the next five years. That future may be in the next 15 years.

What happens between now and 2035 when renewables become the predominant mode of electricity generation in this country? I think there will be a lot of distress that will circle through the markets and will hit a lot of existing assets along the way. It will create reliability issues.

MR. MARTIN: Why reliability if renewables, possibly with storage, are filling the gap?

MR. SAXENA: California is a prime example. There are days when solar and wind are producing out of synch with peak demand, and storage is not quite there yet to solve the mismatch. Gas has been the fuel of transition. The shift to renewables is not going to happen overnight. It will happen over the next 10, 15 or 20 years. I think gas plants will remain valuable probably for another two to three decades.

Counter Investing

MR. MARTIN: Bruce MacLennan, you heard Robert Simmons from Marathon Capital say, on the panel immediately before ours, that the market is still awash in liquidity. Do you agree and, if so, what is the evidence?

MR. MACLENNAN: I agree. You could pick almost any piece of the capital structure.

We own a large renewables development business called Clearway. The pricing we get on construction debt for both wind and solar projects is cheaper than ever for contracted projects that are not as straightforward as they used to be, so that is an example from the bank market.

More broadly, I think we are off to the fastest start in terms of new issue volume in the US high-yield market in history. In the first seven trading days, roughly $17 billion was priced. Maybe even more of a headline was the $12 billion done last week, of which $6 billion, or half the market, was E&P and oil services companies that had largely been out of the high-yield market for the last six months.

MR. SAXENA: I think it depends on what kind of capital is being invested. There is a lot of debt, there is a lot of capital for green investments and there is just a lot of money flowing into solar and wind. But there is not much money flowing into thermal energy projects. Gas and coal are really largely out of favor. Renewables are deeply in favor.

You can also break down the market by revenue structure. If you have anything that looks contracted or has pretend contracts, there is too much money for those deals, but anything that looks merchant has a harder time raising money. Activity in merchant deals was very muted in 2019.

MR. MARTIN: Paul Segal, you said two years ago that it was a good year to sit on the beach. The wall of capital had driven down returns to a level that it

> The markets are starting to break. Capacity prices today in California are six times what they were a year ago.

didn't make sense for developers to develop new projects. In addition to spending time at the beach, you were going to buy 15- and 20-year old gas-fired power projects and spend time on regulated transmission lines. Has anything changed?

MR. SEGAL: Can I back up for a second? I am going to disagree with Himanshu a little. I don't think that things are breaking. I think that they are appropriate price responses to current market conditions. Markets are generally showing that they can work. The fact that we have a material move in a capacity market when capacity is in short supply is exactly what we would want and how a market should function.

I also think there may be an emerging liquidity issue with hedge-counterparties for combined-cycle power plants in PJM.

MR. MARTIN: Not enough of them?

MR. SEGAL: Correct. The interest in building new combined-cycle gas plants in PJM has been puzzling for several years. It was a good area in which to invest 10 years ago. It was probably still an okay idea five years ago. But developing new combined-cycle gas plants in PJM today — and frankly in most of the country — seems like a pretty bad idea and will likely cause destruction of equity capital. I think we are seeing it today. There was an announcement yesterday that some power plants that were just built in this last cycle were turned over to the mezzanine lenders or preferred equity.

I am perplexed about that. I was optimistic two years ago that there would be more deal flow in this space. But the last two years in the gas-fired world has felt a little like 2003 to 2005 when there was a gap between what folks like those of us sitting here would be interested in paying for one of those projects, and what sellers are willing to take.

MR. MARTIN: The bid-ask spread is too wide today.

MR. SEGAL: It has been too wide for the last couple years.

MR. MARTIN: What do others see as opportunities this year? Steve Petricone?

MR. PETRICONE: I agree with Himanshu that there is not a lot of available capital in certain sub-segments within the larger power sector. At Fortress, I sit on the credit side, which represents about 75% of our over $40 billion in assets under management.

But credit is a bit of a misnomer because we have the ability to invest across the capital structure and across sectors within the supply chain and energy.

Probably about half of our investments are in upstream oil and gas. We are also heavily invested in power. We are opportunistic investors. We look for places where / continued page 28

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pay after the government disallowed tax credits they claimed in 2007.

The US used to offer tax credits as an inducement to produce "nonconventional" fuels like gas from landfills and coal seams, synthetic fuel from coal and oil from shale or tar sands. The credits could be claimed on the fuels sold to third parties during the first 10 years after the well or other equipment used to produce the fuel was first put into service. The production equipment had to be in service by June 1998 to qualify.

At least four class-action suits have been filed against the law firm, Chuhak & Tecson PC, that advised the investors in the landfill gas deals. The partner who handled the deals was charged in 2014 with helping clients claim at least $5 million in illegal tax credits during the period 2006 through 2010. He pled guilty to helping to prepare false tax returns and was sentenced to 18 months in prison in September 2017. He has been disbarred and is no longer with the firm.

Other NFL stars who invested include Ray Lewis, a standout former linebacker for the Baltimore Ravens, Terrell Owens, a former Philadelphia Eagles and San Francisco 49er wide receiver, and Kyle Orton, a former quarterback for several teams including the Denver Broncos. Orton sued the law firm in 2011 alleging that he and others lost millions. The suit was put on hold while the lawyer faced criminal charges. Other suits were filed in 2015 through 2018, including one by former Baltimore Ravens cornerback Duane Starks on behalf of himself and other investors.

A US appeals court upheld the disallowance of tax credits on gas produced from 19 landfills on grounds that the gas was flared rather than put to use as fuel. The court said the operators lacked reliable records to prove how much gas was produced and, in some cases, their legal / continued page 29

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there is a lack of capital. Current examples are merchant gas-fired generation and gathering and processing midstream or other sponsor-backed midstream.

We look at these as opportunities because of the disruption being caused by this secular trend from thermal to renewables. Some of that disruption is caused by fundamentals, but some of the disruption in capital supply is caused by an exodus by investors, disproportionate to the risk. We think the actual risk for some investment opportunities may be lower than the perceived risk during this transition. We think that is a really interesting spot.

MR. MARTIN: This reminds me of a book by P.J. O'Rourke called Holidays In Hell. He went into Lebanon on vacation shortly after the outbreak of the Lebanese civil war. He was the only passenger in a boat going in while all the other boats were heading out to sea. You are going into sectors that you say people are fleeing, and that is why there is a shortage of capital. You are looking for a higher yield.

Bruce MacLennan, where do you see the greatest opportunity this year?

Opportunities in 2020

MR. MACLENNAN: There has been a lot of discussion already on this panel about the opportunity or lack of opportunity in thermal power. We were more balanced between thermal and renewables in the past than we are today. In recent years, our focus in the power sector has been almost entirely on renewables.

We will continue to look for platform opportunities in the renewables space. I imagine we will pay more attention to storage. Storage is not yet ripe for a fund of our size, since we have to deploy capital on a large scale, but are paying more attention to the work that others are doing to start up development pipelines and to advance storage assets.

Our goal is to put capital to work, ideally in a platform that has a combination of existing operating assets that provide a foundation and a development pipeline that is meaningful in relation to that base. That type of opportunity offers the best balance of risk profile and return opportunity for us.

MR. MARTIN: Grant Davis said a couple years ago on this panel that storage is like Bitcoin: you can't go to a cocktail party without somebody asking about Bitcoin. You can't go to a power industry conference without somebody asking about storage.

Let's drill down into storage. The panelists on the panel immediately before ours suggested that storage is still a long way off. Bruce MacLennan, why is storage a good investment today? You can lose a lot of money being prescient.

MR. MACLENNAN: I think it is a good area to investigate and then the investigation will reveal how good an investment it is at this point. My sense is that we are reaching a point with so much investment in renewables that the transmission system either needs major upgrades or other fixes like storage to handle congestion.

It is obvious in our renewables development business that interconnection is getting harder. At some point soon, a large portion of the solution to integrating renewables and intermittency is not going to be more high-voltage transmission lines and upgrades and substations, but putting much more meaningful quantities of storage on the system. So it seems time to investigate.

MR. MARTIN: Himanshu Saxena, what are the opportunities this year?

MR. SAXENA: We have been doing this for 14 years, and most of the work in the first 12 was on power. We did a lot of renewables and transmission during that period. We also bought four coal plants, so we have been looking at everything power-related. We saw 2019 as a year where there were not a lot of interesting things for us to do in the power sector. We looked at other opportunities. We did our first midstream deal at the end of last year and then, on December 30, we announced our first chemicals deal. We invested in a $1-billion plant in Texas to convert natural gas into ammonia.

It is a new year. We are stepping back looking at the broader picture. There is too much natural gas. The price of natural gas will remain low for the foreseeable future. Converting it into electrons when there are excess electrons in most markets is not so interesting at the moment. It feels very artificial to build new combined-cycle gas turbines in PJM. Nobody needs them.

So is there stuff we can do with the natural gas? Maybe it is converting gas into LNG or chemicals that can be put on a ship and transported globally. Some of those deals are far more interesting from risk-return standpoint than investing in another solar project with a 5% return or a storage project where you don't know where your revenues are going to come from for the next 15 years because the markets are not ready for it yet. We are having to be far more creative than we were in the last 15 years.

Recession Planning

MR. MARTIN: Does anyone expect a recession this year or, if not this year, then next year?

MR. SAXENA: I think it depends on the elections.

MR. MARTIN: So if Bernie Sanders wins?

MR. SAXENA: Gas prices would go up to $10. Fracking would be dead.

MR. PETRICONE: At least fracking on some public lands. It could have an impact on crude, too.

MR. SAXENA: Seventy percent of fracking today is on public land. We have seen studies that say $2 gas would go to $14 if you ban fracking on federal lands.

MR. MARTIN: What happens then if your strategy is to take advantage of cheap gas, and you have this looming election? Why is it sensible to put all your chips on products that can be made from gas?

MR. SAXENA: We don't make macro bets that the gas prices are going up. We lock in our returns under contracts, so the residual value of the assets is exposed to a structural change, but as long the contracts are alive and you are appropriately structured with pass-through of costs, you are okay. These are 15-year contracts. In 15 years, we may have seen three new administrations.

MR. MARTIN: What changes in your general approach if we get into a downturn in the business cycle?

MR. SEGAL: Not much changes for us. I think we anticipate that there will be a down cycle at some point. A down cycle is frankly historically overdue. Liquidity at some point will flow out, and capital will become less available.

You have to be prepared for that. And you have to be prepared for and thinking about eventualities like what happens if we have an extreme-left Democratic president. We are in a world of political volatility at the federal level and at the state level in many states. You have to plan around what might happen in terms of resource extraction, permitting, new projects and things like carbon pricing.

MR. MARTIN: Is it an opportunity to shift to renewables and out of fossil fuels?

MR. SEGAL: We all have that opportunity now. It is just a question of how you decide to spend your time and capital. My sense is that we will eventually have some version of a carbon tax. More renewables will come into the market over time. Battery storage is not economic in most places today, but it is becoming economic in California, if it isn't already, and much of the rest of the United States is moving slowly from a / continued page 30

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rights to the gas had expired. (For earlier coverage, see "Landfill Gas Tax Credits Disallowed" in the October 2018 *NewsWire*.)

H-S-R THRESHOLDS for notifying the US government of planned acquisitions have been updated.

The new thresholds were announced in late January and apply to transactions that close on or after February 27, 2020.

The Hart-Scott-Rodino Act is an antitrust statute that requires parties to an acquisition to make a detailed filing with the Federal Trade Commission and Department of Justice, and to give those agencies time, usually 30 days, to review the proposed transaction before closing.

Transactions now valued at more than $94 million will trigger H-S-R reporting requirements. There is no H-S-R reporting for any transaction valued at less than $94 million, regardless of the percentage of assets or voting securities to be acquired.

Under a size-of-person test, when the value of a proposed transaction exceeds $94 million, but is less than $376 million, then the transaction must be reported if one party to the transaction has total assets or net sales of $18.8 million or more and the other party has total assets or net sales of $188 million or more.

All transactions valued at more than $376 million must be reported.

OFFSHORE VESSELS generate income that will be taxed in the United States if the vessels help with oil and gas or recovery of other natural resources on the US outer continental shelf.

This is the area between 12 and 200 nautical miles off the US coast.

However, vessels used to install or maintain offshore wind farms should not fall in this category. / continued page 31

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policy perspective to where California is.

MR. SAXENA: There is an old adage among traders: "Don't let the fundamentals get in the way of technicals." We are looking at both today. Somebody offered us a coal plant in Texas for a dollar, so we are making decisions, not whether coal is going to be around for the next 30 years, but whether we can make a decent risk-adjusted return on such an investment in the next five years.

We are at a point today where making a decent risk-adjusted return on renewables is very hard. There is immense downward pressure on prices. There is too much capital. PPA prices are not strong enough. The numbers don't pan out.

Capital is in short supply in certain sub-segments of the power sector.

But you can make a decent return from thermal investments — both gas and coal — if you pick the right spots in the market. So we are not making macro bets on where the power industry is going in the next 30 years. We are looking at what happens in the next five years and how to extract value from that.

Picking Spots

MR. MARTIN: Probably the most interesting story from the previous panel and this one so far is how many of you are looking to invest in fossil fuels. At the same time, you fear it will be a bad bet if the Democrats, particularly Bernie Sanders, win the election. How do you square that?

MR. SEGAL: My perspective is the following. We will need gas in some form to firm the grid for a long time. I think the question is, for how long and how much energy do we need gas- and coal-fired power plants to produce. We need much less energy from coal-fired power plants today than we did 10 years ago because we have more gas-fired power plants, and we have much lower gas prices.

Ten years from now, we will have a lot more renewables, and we will not need as much electricity from combined-cycle gas-fired power plants. What you might think about is how long we will need a combined-cycle power plant to act like a combined-cycle power plant instead of acting like a peaking power plant that will run 2% of the time and provide critical services that the grid will still need.

As we underwrite projects, we think about how quickly we can get our investment down to what we believe can be justified from a cash-flow perspective by operating as a fast-start peaker as compared to a combined-cycle power plant.

MR. MARTIN: Two years ago Himanshu Saxena, you predicted that by 2023, prices would start to fall for renewables assets because people would already have enough of them in their portfolios and they would be moving on to the next shiny thing. Do you still feel that way?

MR. SAXENA: Solar still has a long runway to benefit from investment tax credits. There is also a lot of offshore wind activity now that did not exist two years ago. If we look out five years, purely from an activity standpoint and ignoring returns, I think renewables will remain one of the busiest sectors, whether or not you make money on it.

The question for us is where to pick our spots, whether it is offshore wind, solar, solar + storage or you name it.

MR. MARTIN: We talked a little about the elections. In which direction do you see the cost of capital moving this year?

MR. MACLENNAN: It seems like the cost of capital has been moving down for the last several years. You wonder how much lower can it possibly go.

Take the spread on a construction loan for a renewable energy project, for example. After quite a long period of stickiness, there was a fairly decent move for projects with a better risk profile. For contracted projects, there has also been a pretty decent move down in tax equity flip yields.

My bet is the cost of capital remains flat to down slightly. Balance that against the potential impact of the election and a dramatic change in economic and energy policy that could push the cost of capital a lot higher 11 months from today. It is hard to handicap the risk.

MR. PETRICONE: I agree. The secondary trading markets in some of the institutional loans have been pretty volatile in the last 18 months.

You had spike up in yields and a meltdown in value at the end of 2018. That was startling. That was followed by a kind of flat-line slow recovery. Then suddenly in November and December last year, increased pricing and lower yields in the secondary market, sustained across the project finance spectrum. It suggests a certain amount of volatility that you tend not to see in the primary deals.

MR. MARTIN: It is uncertainty driven by how exposed this sector is to changes in public policy.

Mr. PETRICONE: To changes in commodity prices certainly. Unlike what we have been describing for renewables, a crisis of capital still exists in the upstream space. You have broken capital structures in upstream and that is having a bleed-through effect at least in the commodity-impacted power space.

MR. SEGAL: I think a lot of this comes down to technicals. There is a view among institutional investors that many of them cannot or will not own fossil fuel assets. My sense is that, for the time being, upstream is definitely a fossil fuel asset and midstream may or may not be. Power generation that is not coal is still not a fossil fuel asset. And renewables obviously are not fossil fuel assets.

I think we will continue to have capital migrate toward and push down discount rates and drive investors to make aggressive assumptions around residual value and what will happen in the future. We may see capital costs increase for fossil fuel assets because they have a sort of ESG-taint to them.

MR. MARTIN: Buz Barclay from Rimôn, question?

MR. BARCLAY: Three of the four panelists are private equity investors rather than the institutional investors about which Paul Segal just spoke. You are still looking for yield in investment-grade assets. If you are stepping out of the renewables market as it sounds like you are, do you see other investors moving into it and can you identify who they are?

MR. SAXENA: A: We are not stepping out of the market. B: We are not yield players. C: We are not looking at investment-grade style returns.

The way we look at the business is / continued page 32

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A UK company owned a ship that was used to decommission oil and gas wells in 11 blocks in the Gulf of Mexico on the US outer continental shelf.

It chartered the ship with a crew of 28 during 2009 through 2011 to EPIC Diving & Marine Services, LLC, a US oil services company that specializes in decommissioning oil and gas wells. Decommissioning involves putting deep sea divers on the seabed for extended periods. EPIC had between 40 and 62 people on board, in addition to the crew supplied by the ship owner. Some were its workers and others worked for subcontractors or clients.

EPIC paid the UK ship owner a flat daily rate plus $70 a day for meals for each member of the crew to charter the ship and crew.

The United States taxes foreign corporations on income that is considered "effectively connected" with a trade or business that the foreign corporation conducts in the United States. The foreign corporation must pay taxes on the net income from any such business activity as if it were an American company.

Foreign corporations are also taxed on any income from US sources even if they are not engaged in a US trade or business. US source income includes "[c]ompensation for labor or personal services performed in the United States" and income from renting or leasing "property located in the United States." Taxes are collected on any such cross-border payments by withholding a percentage of the gross payments.

The ship owner said its income from the ship charter was earned outside the United States.

"United States" is defined for most US income tax purposes as just the US states and the District of Columbia, a federal enclave wedged between Maryland and Virginia that serves as / continued page 33

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this. We are in the business of investing patient capital that sometimes takes years to invest. We are developing a transmission line right now in California, something we competed with Paul Segal on five years ago. That is triple-digit development capital, hundreds of millions of dollars to spend, that takes five years to develop. It is not for the faint of heart. It involves a lot of risk and a lot of work. That is the kind of capital that we are putting to work.

Disengage from things that can be management intensive with low potential upside.

After that asset is built, it will become a prime asset for investors that are looking for a low-risk, stable, cash-yielding investment to buy. We are creating assets that we can sell to the wall of capital that we have been talking about.

Those are the kind of deals that we do. Finding those deals was never easy, and it is only getting harder because everybody is looking for similar kinds of deals. Everybody is moving up the risk chain. Folks that never did development are now doing development. Folks that never took commodity risks are now taking commodity risks. Even people who just did contracted deals are now still doing contracted deals, but they are paying enough that they are taking risk by relying largely on the residual value to get to the expected returns.

MR. MARTIN: Is this any different than any other year? People chase the highest returns on a risk-adjusted basis.

MR. SAXENA: It just feels like there is more competition now than I can remember in the last 12 years. Maybe I am just getting old.

MR. MARTIN: We have another question. Name and affiliation?

MS. MCCAIN. Shelley McCain from Shell. Buz Barclay asked this morning how many of us will make a living doing projects that are less than $50 million in capital cost. I counted two raised hands. Yet we are seeing double-digit growth in the distributed energy sector. What will it take to see a shift in investment strategy from utility-scale to distributed energy?

MR. SEGAL: I think it depends to a large degree on policies at the state level. In places like New Jersey, virtually all of the solar investment to date is distributed. There have been virtually no utility-scale solar or wind projects.

Mr. PETRICONE: I think one change that would catalyze distributed generation investment is standardization of financing structures. We have invested in distributed solar in the past, but there is a lot of friction to it. These tend to be small projects. They are idiosyncratic. It takes a lot of time to make an investment.

MR. MARTIN: You are talking about C&I solar, not residential rooftop, correct?

MR. PETRICONE: Correct.

Electric Vehicles

MR. MARTIN: Paul Segal, you are invested in distributed energy. You bought EVgo, a company with electric vehicle charging stations that is essentially a retail supplier of electricity. Why did that make sense to move into that sector?

MR. SEGAL: EVgo has its particular set of economics, but I think broadly speaking, when we look at the trends and objectives of many state governments, to make any real progress on de-carbonization, you have to look beyond the power sector. We have made incredible progress within the power sector. The transportation sector has not made much progress. Many regulators and policymakers recognize that and want to take steps to accelerate electric vehicle penetration. One of those steps is having places to charge. EVgo is a critical component of that infrastructure.

MR. MARTIN: The rate of electrification in the US transportation sector is not terribly encouraging. There are only one million electric vehicles on the road in the United States. Half of them are in California. That is out of a national fleet of 200 million vehicles. Does anyone else see an opportunity to move into electric vehicles for his company? Steve Petricone, Bruce MacLennan, Himanshu Saxena, all three of you are investors.

MR. MACLENNAN: We don't yet, although I agree with everything that Paul said in terms of the direction of travel and the opportunity. It is more a matter at this point of scale where, again, we manage a very large fund. I sit here feeling some envy at the flexibility that Paul has to make more of a niche investment like EVgo. That is not something that would fit well within our portfolio in terms of the scale.

For us to get involved, there would have to be a larger scale and more definition of the business model. What does a revenue stream look like? Who ends up owning it? If the utilities end up owning most of the infrastructure, it will be much less interesting.

MR. MARTIN: You sound like one of the investors on Shark Tank. "So I'm out." Steve Petricone?

MR. PETRICONE: We have not seen opportunities in EV infrastructure yet that are a good fit for us. Part of the problem is the returns are not high enough yet and the business models are not yet well enough defined.

MR. MARTIN: But you seem to like things that are complicated. You did C&I solar. Here you can get in during the early days and help shape the business model.

MR. PETRICONE: Our typical strategy is to take one of two potential routes into a market. One is to be a direct lender to someone like EVgo. Another is to look at the disruption that companies like EVgo are causing up the supply chain and to find another spot in that chain to invest. For example, focus on the disruption caused to internal combustion engine suppliers, bet on their rates of deterioration and potentially be a capital provider to healthier credits among them, as other investors flee.

MR. SAXENA: We used to own a C&I solar company that we have now sold, and we have looked at an electric vehicle company, so we have a basis for comparison. There is a big difference. When you do a C&I solar deal, you know who your customer is. You can have a 15-year contract with the customer. You may not like their credit, but you know where the revenue will come from for the next 15 years.

The EV-charging industry is still figuring out how it will make money going forward. That is very different. There is not as much visibility into how this market will look in the next five to 10 years.

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the US capital. The IRS views the United States for this purpose as extending 12 miles offshore.

However, a special tax code section — section 638 — defines "United States" more broadly to include the outer continental shelf for activities "with respect to mines, oil and gas wells, and other natural deposits."

The UK ship owner argued that its activities were not covered by section 638 because the ship was helping to dismantle wells that were no longer producing.

The US Tax Court disagreed. It said decommissioning is a corollary of oil and gas production.

The ship owner then argued that the United States cannot tax it under the US-UK income tax treaty. The treaty bars the US from taxing the business profits of a UK tax resident unless the UK tax resident has a "permanent establishment," normally meaning an office or other fixed place of business, in the US.

The ship owner had no office in the United States, unless the ship itself qualified as an office. However, a special provision in the treaty — article 21 — treats any company that carries on "exploration . . . or exploitation . . . of the sea bed and subsoil and their natural resources" as having a permanent establishment for treaty purposes. The court said the ship was involved in exploitation of oil and gas. Decommissioning wells is part of that business.

The case is *Adams Challenge (UK) Limited v. Commissioner*. The Tax Court released its decision in early February.

EPIC may have been engaged in the oil and gas business on the US outer continental shelf. The court concluded a ship owner who leased a crewed vessel was as well.

The parties will go another round in court over what deductions the ship owner can claim to reduce its US net income.

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MR. MARTIN: Two more questions. Congress, on December 20, reversed course and increased the tax credit for wind projects that start construction in 2020 compared to 2019. There was the huge slamming of the brakes, with wind developers trying to rescind or cancel arrangements they put in place in 2019 to start construction so that they can qualify for higher tax credits. What effect do you see the one-year extension for wind having on the market?

MR. SEGAL: Incrementally more projects will be built. We are working on a large-scale project out west on which the contracted revenue is lower than we would like. A larger tax credit means the project is more likely to get done.

MR. MARTIN: It helps offshore wind. Those projects got a later start than the rest of the industry and need more time to start construction. Does it drive more business to Texas where it is easier to build projects quickly?

MR. MACLENNAN: I agree with Paul Segal that the effect is incremental. A lot depends on the facts and circumstances. LS Power has a project where the incremental economics will be helpful. Repowerings that are on the margin economically might also be helped where you have not quite gotten to the terms you needed in a restructured offtake contract. An extra 20% in tax credit value might be enough to tip the scale. However, overall, this is a relatively modest and short-dated extension of economics.

Life Lessons

MR. MARTIN: Last question. Steve Petricone, starting with you and then going across the panel, what lessons have you learned in a long career as an investor?

MR. PETRICONE: The markets are usually pretty efficient, and if you are going to take a contrarian view, you had better have done a lot of work to justify it.

MR. MACLENNAN: If we had something generic that we could have done better across the 14-year history of our firm, it would have been imagining broader ranges of outcomes. That is not only in a negative way. We have had investments where the outcome was far beyond the upper end of any sensitivity analyzed when we made the investment, and we have had a couple that have gone in the other direction. So try to imagine the unimaginable, but more realistically, broaden the range of things that you at least consider when making the investment decision.

MR. MARTIN: Thomas Jefferson said the older he got, the more he realized he didn't know. Himanshu Saxena?

MR. SAXENA: What I have learned over the last 14 years is that there is a component of luck in our business. There are certain things that go right and there are certain things that go wrong, and despite all the due diligence up front, all the analysis and just thinking through every single piece of the risk, there are things that happen over which you have no control. There is inherent risk in our business and a lot of this risk cannot be controlled. Luck favors the prepared, but you still need luck.

MR. MARTIN: Paul Segal, what have you learned as a developer?

MR. SEGAL: I have learned that we live in a cyclical business, especially if you are willing to take the commodity risk component of what we do as electricity generators. It is a business that can stay irrational in both directions for longer than you might expect, both to the upside and the down.

The other thing I have learned is in the context of running a business. We are as good as the management and intellectual resources that are sitting around our table, and one of the things that we very actively seek to do is to disengage from things that can be management intensive with low potential upside. ◎

Renewables and PJM Capacity Auctions

by Robert Shapiro, in Washington

The Federal Energy Regulatory Commission is likely to hold a rehearing of its controversial decision in late December to require renewable energy and nuclear generators bidding into PJM capacity auctions to bid a minimum offer price.

Four states have threatened to withdraw from PJM and the New England ISO if the order stands.

Many parties, including PJM, have filed substantial rehearing requests. Any rehearing order on the merits would not be issued before the end of February at the earliest and will probably take longer given the number and complexity of the issues.

PJM has still not held its 2019 capacity auction, and the 2020 auction is expected to be delayed. The auctions are for capacity to be supplied three years in the future.

FERC currently operates with only three commissioners. There are two vacancies. It needs at least three to conduct business. Bernard McNamee, one of the remaining three commissioners, said in January that he will leave at the end of June, but he said he would remain until his replacement is confirmed. At least two of the three commissioners must agree on the approach to the capacity auctions.

The December order imposing a minimum offer price has generated significant public opposition from nearly every segment of the non-fossil-fueled resource stakeholders, including renewable power developers, states that have substantial clean energy policies or nuclear power or offshore wind incentives, and ratepayer advocates.

There seems little doubt that the order, if implemented as written, will have the effect, if not the intent, of increasing the costs to ratepayers in PJM states that provide and are committed to provide and maintain significant climate change-related incentives and increase the likelihood of dispatch of coal-fired generation.

Whether it will significantly slow development of renewable energy in the region is less clear, as that may depend on how individual states respond to the capacity market impacts from the order.

PJM is the section of the US utility grid that covers 13 states and the District of Columbia from Pennsylvania, New Jersey, Maryland and Delaware west through the rust belt to parts of Illinois and Michigan. / *continued page 36*

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THE FOREIGN CORRUPT PRACTICES ACT can be used to prosecute a foreigner who pays a bribe to win a contract outside the United States if the US government can show he is acting as an agent for a US company.

A federal district court in Connecticut was expected to sentence Lawrence Hoskins, a former Alstom executive, as the *NewsWire* went to press.

Hoskins was charged in 2012 with helping hire consultants during the period 2002 through 2004 who were paid a percentage of a $118 million contract that Alstom won with PLN, the state-owned power company in Indonesia. Prosecutors said the consultants used part of the money to pay bribes to win the contract.

Hoskins is British. Alstom is a French conglomerate. He worked for Alstom in Paris and was never physically in the US during the period.

A US appeals court blocked prosecution in August 2018 unless the prosecution could show a link to the United States. (For earlier coverage, see "Prosecuting Foreigners under the FCPA" in the October 2018 *NewsWire*.)

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

US prosecutors can charge a foreigner only if they can show that he committed the crime while present in the United States or while working as an agent for a US company or for a foreign company whose securities are either traded on a US exchange or over-the-counter market or widely held in the United States.

US prosecutors said that Hoskins approved hiring the consultants and knew that part of what they were paid would be used for bribes. Several parts of the scheme were executed in the United States. Several Alstom executives attended meetings in the US about the scheme */ continued page 37*

PJM Auctions

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Minimum Offer Price

PJM holds annual auctions, known as the base residual auctions or BRAs, to set the capacity prices and the capacity commitments for projects that are lucky enough to be selected in the auction for a future delivery year, typically three years ahead.

There are also intermediate annual auctions, called incremental auctions, that permit PJM and existing or potential suppliers to buy and sell capacity committed in a particular BRA delivery year.

The MOPR order may or may not slow renewable energy development, but it will increase electricity prices for consumers.

Projects that are subject to the minimum price offer rules, or MOPR, have to offer that minimum price in the auction and run the risk of being shut out of selection if the clearing price is lower than the MOPR.

As a general matter, the order requires bidders that qualify for a state subsidy on a project to bid a minimum offer price in each annual PJM capacity auction, subject to very limited exceptions.

The prior PJM rules included a minimum price rule or MOPR requirement, but only for new gas-fired resources. For the first time, in addition to new gas-fired resources, renewable energy projects, capacity storage projects, demand-side resources and energy efficiency resources qualifying for state subsidies will have to bid a minimum offer price in each capacity auction.

Also, for the first time, all existing projects with such subsidies will have to clear the market each year under the new default rate as well. Previously, new projects subject to the MOPR requirement had to clear in only one auction and then were deemed existing projects and were permanently exempted from the MOPR requirements thereafter.

Further, for the first time, "self-supply resources" will have to meet the MOPR requirement, subject to very limited exceptions. "Self-supply resources" are generating facilities belonging to vertically integrated utilities, electric cooperatives and municipal entities that the utility uses to supply electricity to its own retail customers.

In addition, the minimum offer price will now be higher than before. It will be set for new projects at 100% of the net cost of new entry or "Net CONE," rather than at 90% of Net CONE. This will create a higher hurdle for subsidized projects (and gas-fired projects) to be selected for capacity in the capacity auction. The Net CONE is based on a levelized single year of revenues needed to recover capital and fixed costs of a new combustion turbine, adjusted for variable operating costs, net of expected revenues for energy and ancillary services.

If the clearing price in the annual auction is determined to be below the resource's MOPR bid, that resource will not receive any capacity payment.

State subsidies that subject a generating facility to the requirement to bid a minimum offer price are very broadly defined and would include, among other things, both state mandatory and voluntary renewable energy credit (REC) programs, subsidized demand side and capacity storage resources, as well as zero emission credit programs subsidizing certain nuclear plants and OREC or offshore renewable energy credits for offshore wind projects.

PJM wanted to limit the MOPR requirements to projects above 20 megawatts in size on the ground that small projects would not have a material effect on the market. However, FERC rejected any minimum size threshold for application of the MOPR to projects that qualify for state subsidies.

FERC directed PJM to make a compliance filing by late March implementing the various changes ordered by the commission as well as providing support for a number of such changes.

In the meantime, dozens of intervenors filed petitions for a rehearing of the FERC order. The intervenors include PJM, which asked for more time to implement the MOPR order and the many requests for clarification and rehearing of many aspects of the order from other intervenors.

Some aspects of the FERC order will probably be clarified or revised on rehearing and necessitate an additional filing by PJM if the original compliance deadline is not extended.

The process will take time to play out fully.

After FERC decides whether to hold a rehearing, it will issue another order. If that order in any way modifies the prior order, then the revised order will also be subject to rehearing. The FERC orders will almost certainly be challenged in a US court of appeals. While the appeals will not prevent the base residual auctions from going forward based on the orders, there is a risk that that the outcomes of those BRAs could be undermined by an adverse ruling by the appeals court on review, which could take more than a year to decide the challenges.

The auction that was supposed to have taken place in 2019 will now be rescheduled, but further delays are possible.

FERC directed PJM to propose a new schedule to set commitments for the 2019 BRA, meaning the June 1, 2022-to-May 31, 2023 delivery year, and for the 2020 BRA, which would establish commitments for the June 1, 2023-to-2024 delivery year. The 2019 BRA was supposed to have occurred in May 2019, three years in advance of initial delivery, and the 2020 BRA is supposed to be held in May 2020, which will not happen.

Several major resource providers are urging FERC to delay any PJM auction until FERC clarifies its December order, which could push the next auctions into 2021, although the 2019 BRA would need to address the delivery year starting June 1, 2022 and the 2020 BRA would need to address the delivery year starting June 1, 2023.

State Subsidy Defined

FERC adopted a broad definition of a state subsidy that will require a project to bid a minimum offer price.

The term means "[a] direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction."

This definition is in marked contrast to the narrower definition that PJM wanted.

PJM wanted only a "material subsidy" to require a generator to bid a minimum offer price. FERC / continued page 38

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and made calls and sent emails about it while on US soil. The bribes were paid from Alstom bank accounts in the US and went into a US bank account of one of the consultants.

Nevertheless, the appeals court said Hoskins could not be charged as an accomplice or co-conspirator of others whom the statute can reach.

The judge told the jury that to conclude Hoskins was an "agent" of the Alstom US subsidiary, which was the only way to convict him, there would have to be evidence that he was appointed by the US subsidiary, accepted the assignment and understood that he was working under the direction of the US subsidiary.

The jury took a single day to decide he was such an agent after an eight-day trial.

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

INCOME FROM SELLING TAX CREDITS counted as good income for real estate investment trusts.

Two REITs are developing one or more mixed-use real estate projects on land that was contaminated by hazardous waste. The state where the projects are located offers tax credits that are a percentage of the amount spent on cleaning up the sites. The sites must be in economically distressed areas to qualify.

The tax credits can be sold to a corporation or non-profit entity for cash.

The tax credits in this case will be sold. The REITs will have to report the sales proceeds as income.

REITs are corporations or trusts that do not have to pay income taxes on their earnings to the extent the earnings are distributed each year to shareholders.

Howhever, they must be careful to ensure their assets are largely real estate and their income is largely passive income from the use of real estate. / continued page 39

PJM Auctions

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completely eliminated the materiality component, making any incentive, from 5¢ to $5 million, enough to trigger a minimum offer requirement.

The FERC definition is too vague. PJM will have a hard time figuring out whether some bidders are subject to it. For example, what is the universe of "indirect payments . . . or other financial benefit that . . .(3) will support the construction, development or operation of a new or existing capacity resource or (4) could have the effect of allowing a resource to clear in any PJM capacity auction"?

FERC said its "concern is with those forms of State Subsidies that are not federally preempted, but nonetheless are most nearly 'directed at' or tethered to the new entry or continued operation of generating capacity" in the PJM market.

The word "tethered" is a loaded reference, as it was the same word used by the US Supreme Court in the Hughes v. Talen decision. In Talen, the Supreme Court invalidated a state-mandated contract because it required the developer to clear the PJM capacity auction in order to receive the fixed payment under the contract. The PJM capacity tariff is a wholesale rate. FERC has exclusive jurisdiction over wholesale rates. Therefore, the state contract was "preempted" by federal law, the court said. (For more information, see "Supreme Court Nixes Two PPAs" in the June 2016 *NewsWire*.)

The contract was a so-called contract for differences, in which the contract price was netted against payments received by the seller from the PJM capacity market. The Supreme Court said its decision was a limited one that permits states to take action to encourage production of new or clean generation through measures "untethered to a generator's wholesale market participation."

Lawyers have debated what "untethered" means. FERC has taken that vague pronouncement about federal preemption, and compounded the ambiguity further, by expressly stating that a minimum offer price by bidders who qualify for state subsidies that, unlike the contract in Talen, may not be federally preempted, but are nonetheless "tethered" to the wholesale market participation.

FERC clearly had in mind projects that qualify for renewable energy credits or RECS under state renewable portfolio standards. RECS are a creature of state law, not federal law.

FERC said it could not rule out that "voluntary REC arrangements . . . [that] are not associated with a state-mandated or sponsored procurement process" would also require a bidder to bid a minimum offer price.

Its argument is that RECs sold to a third party could later be resold to a utility under a state RPS obligation.

This suggests that even corporate PPAs could be captured by the state subsidy definition, even though the corporate buyer has no legal obligation under state law to purchase RECs and the generator cannot benefit from the RECs that are transferred to the corporate buyer. Presumably a commitment by the buyer to retain or retire the RECs once transferred to the buyer would convince FERC that no state subsidy is involved. But the mere assertion by FERC that a REC sale to a corporate buyer with no state REC requirement and therefore literally no state subsidy could nonetheless cause a renewable project to trigger the MOPR rule strongly supports the dissent by Commissioner Richard Glick that FERC is targeting renewable projects in order to favor fossil-fuel projects in the PJM market.

FERC considered and rejected adding to the MOPR any federal subsidies that can give a project a competitive advantage in the PJM capacity auction. The reason is that federal subsidies are a product of federal law, and FERC has no authority to nullify the effect of a federal law, it said. However, the Glick dissent points out, there is a logical inconsistency between the argument made by FERC in support of the state-subsidized MOPR requirement and the argument for excluding the federally-subsidized projects: since FERC argued that its orders mitigating the effects of state subsidies did not prevent states from applying those subsidies, a FERC order that would mitigate the impact of federal subsidies would not prevent the federal government from applying those subsidies either.

It will ultimately be up to the US court of appeals to decide whether this federal-versus-state rationale for the dividing line on subsidies is legally supportable.

FERC also excluded from the state subsidy definition any generic industrial development and local siting support because FERC assumed these state benefits would be available to "all businesses."

Exemptions

Three types of renewable generators are exempted from the need to bid a minimum offer price.

The obligation does not apply to any project that successfully cleared an annual or incremental PJM auction before FERC issued the MOPR order on December 19, 2019.

It does not apply to a project that signed or filed an interconnection construction service agreement with PJM before December 19.

It does not apply where a bidder qualifying for a state subsidy persuades FERC to grant it a competitive exemption by committing not to use the state subsidy.

But if a new resource gets a competitive exemption in the first year and later uses the state subsidy, then it will be barred from participating in the future capacity market for up to 20 years.

This draconian outcome can be avoided under something called a "unit specific exemption." The exemption permits an individual project to apply to the PJM market monitor to offer a lower-than-MOPR price if it can show that its expected costs and revenues are low enough to justify a bid below the MOPR level. FERC directed PJM to give a better explanation of the methodology and standards that will be applied when assessing claims by bidders that the net costs of a project should allow a bid below the MOPR price.

Richard Glick said in dissent that he expects most projects to apply for the unit specific exemption to reduce their minimum bid price below the MOPR rate. He said this will effectively convert the PJM capacity market from one relying on competitive market forces, as originally intended, to one that is based on administratively determined cost-of-service rates established by the market monitor.

A substantial percentage of state-subsidized renewable resources, capacity storage and demand resources may still find it possible to finance projects without counting on capacity revenues from PJM.

However, at some point, the effective exclusion from the capacity market may end up causing states to have to offer more state support to reach renewable energy goals.

In addition, by maintaining currently uneconomic capacity in PJM by placing a high barrier for new resources and thus failing to account for the capacity attributes of renewable, storage and demand resources, retail ratepayers that bear the cost of state subsidies for those resources will also bear significant additional costs under the PJM tariff. PJM requires all utilities and other retail electricity suppliers to obtain capacity commitments to meet projected retail demand. By excluding the capacity value of operating state-subsidized resources in PJM and including other resources to fill that perceived demand, retail ratepayers will have to pay more. FERC did not provide any analysis of the potential rate impacts of its decision.

Existing Resources

For existing state-subsidized resources, which are planned resources subject to the MOPR that */ continued page 40*

IN OTHER NEWS

There is both a 95% and a 75% income test. At least 95% of the REIT's gross income each year must come from dividends, interest, rents from real property, or gain from the sale of stock, securities and real property. At least 75% of gross income must come from rents from real property, interest on mortgages secured by real property or gain from sales of real property.

The REITs asked the IRS for a ruling that the income from tax credit sales is good income. The IRS said yes.

The key, the IRS said, is the state tax credit program provides an incentive to redevelop real estate. Thus, the tax credits are an inducement to engage in a permissible activity for a REIT.

The analysis is in two identical private letter rulings made public at the end of January. The rulings are Private Letter Rulings 202005017 and 202005018.

GOOD QUOTE.

The United States allows US companies that pay income taxes to other countries on foreign earnings to credit the taxes paid against any US taxes that must be paid on the same income. However, the foreign tax credit rules are full of fine print. It can be hard for US taxpayers to benefit from foreign tax credits.

The IRS issued new foreign tax credit regulations in December.

John Harrington, a lawyer with Dentons, wrote, after working through the new regulations, that saying US companies have to jump through numerous hoops to claim foreign tax credits is "an understatement comparable to saying 'Odysseus had some trouble getting home from Troy.'"

— contributed by Keith Martin in Washington

PJM Auctions

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have cleared the PJM auction, in subsequent auctions they will need to offer a minimum or default price, but one that is lower than the initial MOPR for planned resources.

The default price has been labeled the "net avoidable cost rate" or NCR. The NCR will vary by resource type. It is an estimate of how much revenue the resource requires, in excess of energy and ancillary services revenues, in order to provide capacity in a given year.

PJM is required to come up with value for each resource type for each year in its compliance filing. In his dissent, Commissioner Glick argues (as did the PJM market monitor, which has to evaluate these costs, in its comments to the commission) that it is illogical to permit existing revenue resources to bid a different minimum rate than new, planned resources because their respective resource costs and revenues will not materially differ from one another.

Net CONE, the MOPR for new resources, is a leveled annual value for a 20-year operating period, and this value therefore should not change from year one to year two. However, setting a minimum price at the lower NCR level in subsequent years will make it easier for existing state-subsidized resources to clear the market if they can get past the initial MOPR-required hurdle.

State Exits

Several states with extensive climate-change agendas have indicated that they are evaluating whether to direct their in-state utilities to exit the PJM capacity market altogether.

Under the existing PJM rules, which are not being modified, a utility or other retail supplier that has an obligation to serve a designated service territory at retail can avoid participation in the PJM capacity market in a delivery year if it demonstrates a commitment to serve all of its customers' capacity demand with non-PJM capacity and also remove its entire system load from PJM market for the applicable delivery year.

This opt-out option is called the "fixed resource requirement," or FRR. The utility would avoid any capacity obligation in PJM and avoid any PJM capacity reliability charge associated with a shortfall in capacity requirements.

The interstate interrelationships among most utilities in the PJM market would make any state withdrawal extremely complicated to accomplish. The mere fact that some states are evaluating the option shows the extent of concern and dissatisfaction with the FERC's actions. ◎

Renewable Project Sales: Established Tactics and Emerging Trends

by Becky Diffen and Sam Porter in Austin, and Megan Ceder Savage in Houston

Negotiations around sales of renewable energy projects follow predictable patterns. That said, there are several emerging new trends in the M&A market in the United States for such projects.

Laying the Foundation

Anyone already familiar with such projects should skip to the next section.

Renewable energy projects have three distinct phases: development, construction, and operation. North American renewable energy projects usually change hands either during the development stage or after they are in operation, although mid-construction sales are becoming more common.

During the development phase, a project goes from a budding idea in a developer's brain to a bundle of legal rights and data sufficient to construct the project. There are two core rights without which a project cannot exist: land rights and grid interconnection rights. There are additional rights, reports and studies that vary based on location and that add certainty and value to a project, such as tax abatements, permits, zoning, wind or solar resource reports, geotechnical studies and transmission studies. And arguably the best way for a developer to increase the value of her project is to find an offtaker.

During the construction phase, a renewable energy project goes from being a bundle of legal rights to a built project, with commencement of construction (notice to proceed) and commercial operation respectively bookending the construction phase. The operational phase begins at commercial operation and lasts as long as the project continues to function economically.

Developers use personal and corporate debt and equity to fund initial development efforts. Once a development project has advanced enough to require credit support for interconnection, offtake or equipment supply, the developer may sell the project to a better-capitalized developer or finance the credit support requirements with additional corporate debt and equity or non-recourse debt if available. The most significant capital outlay for a project comes during construction and, for utility-scale projects, it typically takes the form of construction and bridge loans that are paid off or convert to term debt once construction is complete and tax equity has funded.

As a project moves from being an intangible concept to a tangible asset, the risk that the project will not materialize is reduced. The rewards of ownership become increasingly quantifiable. To drive up the purchase price, a seller tries to portray its renewable energy project as being as close to "shovel-ready" as is credible. Potential buyers will portray the same project as being underdeveloped and risky. If the bid-ask spread is narrow enough and there is an agreed theory of the transaction, the project will trade. There might be an exclusivity agreement or a letter of intent as a precursor to the purchase and sale agreement, and there may be a development services agreement accompanying the purchase and sale agreement.

Purchase Price

How much money will change hands, and when, is the crux of the trade.

Some purchase and sale agreements have a simultaneous signing and closing, while others have an interim period during which certain conditions precedent must be satisfied. Signing and closing can occur anytime during the development phase. Signing consideration is usually tantamount to a partial return of capital, reimbursing some of the developer's expenses to date, and closing consideration is typically an agreed-upon amount that reflects the value of the project at that particular stage of development. The less developed a project is at closing, the larger the percentage of the purchase price the buyer will withhold for post-closing milestone payments, similar to an earn-out.

There might be additional payments when certain milestones are reached, such as a development-completion payment, a notice-to-proceed payment, and a commercial-operation-date payment, or there might be milestone payments specifically tailored to the project, such as payments if additional acreage is leased, a power purchase agreement is signed or a tax abatement is obtained.

A seller will not want to bear risk for things in the buyer's control, such as financing and construction, and will argue that any back-weighting of the milestones should stop at development completion and not extend to notice to proceed with construction or commercial operation.

Buyers conversely will not know whether the development assets they are purchasing will bear fruit as intended until commercial operation and will want to hold back as much consideration for as long as possible.

Any milestones should be defined clearly and objectively to avoid acrimony later. For example, be clear that notice to proceed means issuance of a FULL notice to proceed and for which contracts (for example, engineering, procurement and construction contract, turbine supply agreement, balance-of-plant construction agreement). If the buyer might perform some tasks itself or issue a number of limited notices to proceed, consider adding other milestones for significant work or equipment delivery on site. For commercial-operation-date payments, be sure to tie the payment date to commercial operation as defined in a particular contract (and make sure the contract defines the term) or else refer to mechanical or substantial completion under the construction contract or use an appropriately defined term in the interconnection agreement.

The purchase price is often based on dollars per watt (direct current in a solar project) of nameplate capacity. Payments made before notice to proceed with construction — called NTP — are typically based on an agreed estimate that is adjusted later — trued up — to the nameplate capacity in the construction contract when construction starts and then later to the as-built nameplate capacity at commercial operation. Simple capacity true-up provisions might not address complexities that can and do arise, such as when a buyer acquires additional acreage itself or from a third party, but uses the seller's interconnection rights. Sellers may also require a floor price to ensure the buyer uses the full capacity of the project that the seller developed and for which the seller wants to be paid.

A separate development services agreement is a way to give the seller part of what would otherwise have been a back-weighted purchase price in the form of a monthly service fee. A development services agreement can be a way for the seller to remain involved in the project through to completion, but sellers should be wary of default provisions that could allow for termination of the contract for minor breaches before the bulk of the consideration is paid. Development services agreements also have the potential to convert the amounts received into ordinary income for performing services as opposed to capital gain from sale of the project.

Sellers will often argue that any post-closing milestone payments must be protected in the event that the buyer does not develop the project. What if the buyer / continued page 42

Project Sales

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is just trying to take the seller's project off the market to boost the value of one of buyer's other projects? Negotiations around a buyer covenant to develop the project tend to break down over subjective good-faith and commercially-reasonable-efforts standards.

Sellers sometimes convince buyers to allow the seller an option to buy the project back, but the details are difficult: what are the buyback trigger events, price, terms and conditions? What if the buyer returns the project to seller in worse shape than when the buyer bought it? Outside dates on milestone payments can help a seller gain comfort that the buyer will continue to develop the project. For example, the buyer's failure to make a milestone payment by an outside date would trigger a buyback right for the seller.

Sellers will also often argue that any post-closing milestone payments must be backstopped by a creditworthy entity. If a buyer parent guaranty or a letter of credit is not available, then a seller might offer a lien on the project in the amount of the post-closing payments. Buyers will require any such seller lien to be subordinated to any liens arising under any construction or project financings or under any offtake or hedge agreement, and buyers should expect that construction or project financiers will request that seller's right to a lien be terminated before construction starts.

Conditions Precedent

As in any M&A transaction involving an interim period between signing and closing, buyers will require certain conditions precedent be met before closing.

Third-party consents and regulatory approvals (such as CFIUS and public utility commission filings) tend to be relatively uncontroversial, but are important to identify early in the transaction.

Buyers have a list of development tasks they usually want completed before they will close. Sellers try to move as many of these after closing as the buyer will allow.

Sellers should think through possible mitigants when accepting crossing agreements, title-cure measures and other real property matters as conditions to closing: could the issue be designed around or addressed with insurance?

Sellers should also be aware that recipients of estoppel requests tend to see them as an opportunity to charge money. Conditions precedent involving unincentivized third parties tend to be unpredictable and should be factored into timelines. The theory of the transaction, meaning how the seller and buyer are sharing development risks and rewards, should manifest itself most obviously in the sorting of development items into conditions precedent and post-closing milestones.

The parties should also pay close attention to how each condition is defined to avoid disagreement later about whether an item has been completed.

Other Provisions

The seller's representations and warranties are important to the buyer as a diligence-and-disclosure mechanism — the disclosure schedules in particular are an important part of diligence — as a risk-allocation mechanism through the indemnification provisions, and as indirect conditions precedent given that the seller's representations and warranties usually must be true and correct in all material respects as of the closing date.

The seller will make representations and warranties about the project assets as well as the project company. A renewable energy project in the development stage is not an operating business that is generating revenue. A seller will ask that standard M&A representations be pared back accordingly, and the buyer will ask to tailor the representations to the project and the available diligence materials.

Project auctions are starting to feel like cost-of-capital shootouts. Many buyers are feeling auction fatigue.

Many representations are routine and not controversial, but there is a handful where disagreement is likely. One is the so-called sufficiency representation. Buyers will ask that the seller state that all the assets, including all real property, contracts, permits and studies, are sufficient to develop, construct and operate a project with the estimated nameplate capacity. Sellers will argue that construction and operation are the buyer's responsibility, that other representations adequately address the individual assets, and that the seller cannot guarantee the ultimate size or productivity of an unbuilt project. Title work may not be completed by closing and crossing agreements cannot be finalized until the design is final, which rarely happens by closing for a development-stage transfer.

Another is the so-called 10b-5 representation, named for the section of the 1934 Securities Exchange Act from which the main verbiage is drawn. Sellers try to push back wholesale on the provision as a liability trap, although they often find themselves begrudgingly agreeing to a limited and qualified version, particularly if they have limited negotiating power in the transaction.

If the project is supposed to qualify for federal tax credits, the buyer will almost always require a representation that it was under construction in time for tax purposes to qualify. Sellers offer to represent facts that will allow the buyer to draw its own conclusion rather than represent a legal conclusion.

The disclosure-schedule-update provisions addressing when a change during the interim period between transaction signing and closing should relieve the buyer of its obligation to close and what indemnity the buyer should be paid for breaches of representations are also heavily negotiated. Buyers often already have a no-material-adverse-effect condition precedent, but the material-adverse-effect standard requires a significant change, and buyers might use the disclosure-schedule-update provisions as a mechanism effectively to lower that materiality threshold. These provisions tend to be long, wordy and full of double negatives, so the parties should pay close attention to ensure that they do not have the effect of rewriting the conditions precedent.

New Trends

Renewable energy projects have been receiving greater attention from investors and lenders, and many buyers report a weariness toward managed-and-marketed sales processes.

This "auction fatigue" reportedly feels to buyers like a cost of capital shootout. Particularly if the project is being marketed as "shovel-ready," incongruous buyer and seller theories of the transaction may be latent in the bid stage only to appear in the purchase and sale agreement, after both parties have spent considerable time and effort on the transaction. Some buyers abstain from auctions altogether, while most participate selectively while simultaneously pursuing bilateral relationships with individual developers giving the buyer informal or formal access and visibility into the developer's pipeline.

Many developers, investors and lenders have at some point tried their luck on a project where there was a binary risk, such as a state or local incentive for which the project either qualified in full or not at all. This strategy can work if spread out over a portfolio, but in isolation can squander precious resources. Most developers, and increasingly equity investors, prefer non-binary risks that can be controlled or mitigated with effort, and as a result many larger institutions are becoming better-versed at development. As the universe of developers has become deeper and more diverse, we have seen more portfolio acquisitions, which might be documented in multiple single-project purchase and sale agreements or a single portfolio-wide purchase and sale agreement, and we have also seen more corporate platform M&A where a strategic or financial player will acquire an established developer to bring the development expertise and ability to generate a project pipeline in-house.

Another trend in the marketplace for North American renewable power projects is an increase in foreign buyers, particularly from Asia. One result is that sellers should assume a full CFIUS process into their closing timeline. This can add four to five months. CFIUS is an inter-agency committee of 16 federal agencies that reviews foreign acquisitions of US businesses and assets for national security implications. Filings used to be voluntary, but are now mandatory in some transactions. (For more detail, see "Scrutiny for US Inbound Investments" in the October 2019 *NewsWire*.)

As regulated utilities and the regulatory commissions have become increasingly open to renewables, we have seen a shift from utility power purchase agreements toward build-transfer or build-own-transfer agreements. Utilities often require that their power purchase agreements contain regulatory-out clauses, meaning that if the utility is unable to pass through to its ratepayers the amount it pays under the contract for electricity, the utility can terminate the power purchase agreement. Projects with power contracts with regulatory-out clauses are hard to finance. Developers counter by asking utilities to put their power purchase agreements through a full regulatory approval process before construction starts, to which utilities respond, "Fine, in that case perhaps the utility should just own the project." The resulting build-transfer agreements are like a purchase and sale agreement with a full engineering, procurement and construction contract pasted in as a condition precedent to closing. (For more discussion, see "Emerging Themes in Build-Own Transfer Agreements" in the December 2019 *NewsWire*.) ◎

DFC Replaces OPIC

by Kenneth W. Hansen and Rachel Rosenfeld, in Washington

The Overseas Private Investment Corporation changed in January into the United States Development Finance Corporation. The DFC is endowed with enhanced authority meant to enable it to compete more effectively with China's support of infrastructure in emerging markets.

Several enhancements have been well reported in the trade press. These include the doubling to $60 billion of the maximum size of the agency's portfolio (up from OPIC's $29 billion), its authorization to make equity investments, the abolition of US eligibility requirements for the beneficiaries of guaranties and political risk insurance, and the transfer to DFC from US Agency for International Development of the Development Credit Authority.

This article looks in detail at how the so-called Build Act under which the DFC will operate differs from the OPIC statute and identifies assorted ways in which DFC's capacity has been enhanced, or at least is different, relative to OPIC.

Several of those differences will substantially increase both the availability and attractiveness of DFC's financial products.

Key Programs

DFC may make loans or guarantees "upon such terms and conditions as [DFC] may determine." This broad authority relieves DFC from various constraints on OPIC's lending programs. OPIC could make direct loans only to projects involving US small businesses or cooperatives. Other financing had to be provided by issuing loan guarantees of commercial financing. Nor could OPIC provide direct loans to for oil or gas extraction projects. OPIC had an annual cap of $4 million on guaranteed loans for financing extractive projects. None of these constraints continue as a statutory matter. What constraints might continue as an underwriting or policy matter remains to be seen.

Although the Build Act relaxes OPIC's requirement of a US connection, it does not eliminate the relevancy of US connections. The DFC must give preferential consideration to projects involving United States citizens. The extent to which the absence of US ownership or other connections may impede access to DFC support is not yet clear.

OPIC's lending operations were tied in two ways to supporting investment by US entities. First, the beneficiaries of OPIC guarantees had to be "eligible investors," although the statute did not restrict the ownership of the borrowers or project sponsors. Recognizing the fundamental focus of its statute to encourage US investment in emerging markets, OPIC self-imposed a rule of thumb whereby OPIC would only make or guarantee loans to projects that are at least 25% owned by US citizens. Since this was not a statutory requirement, this restriction was relaxed on occasion, but not often.

In recent years OPIC revised the 25% US ownership rule of thumb to allow the requirement for a US connection to be satisfied not only by ownership, but also by other US involvement, such as procurement or US contractors in the construction or operation of the project.

But even this limitation blocked OPIC's support of meritorious projects lacking adequate US connections. This impaired OPIC's competitiveness with other development finance institutions that had no such nationality restriction. Ironically, even US investors could be incentivized to avoid using OPIC support when developing a project jointly with non-US investors.

While DFC will value US involvement in projects, it faces no bright line impediment from supporting purely international projects.

Financing Terms

The DFC is expected to offer a maximum loan size well above OPIC's $400 million limit (absent special board approval).

The DFC can provide financing for up to 25 years (versus a 20-year limit on OPIC-guaranteed financing).

For guaranteed loans, the corresponding equity investment cannot be less than 20% of the guaranteed loan amount. (In contrast, the OPIC statute permitted loan guarantees of no more than 75% of the total investment committed to any project.) Eighty percent leverage is unusual in DFI-financed projects, so this is unlikely to be a practical issue. Although the Build Act imposes no leverage limitation on direct loans, there, too, underwriting concerns will similarly limit the ratio of debt to equity.

The DFC may make local currency loans and guarantees so long as the DFC board determines there is a substantive policy rationale for doing so. OPIC, in contrast, could provide financing in foreign currencies, but only to projects involving United States small businesses or cooperatives.

OPIC could only provide loans to projects sponsored by small businesses. Thus, most OPIC financing for large projects was implemented as OPIC-guaranteed loans, funded by placing certificates in the bond market. The DFC statute has no such restriction on direct lending to projects sponsored by large companies. The future of OPIC's loan guarantee funding program will depend on its commercial competitiveness now that the statutory requirement is gone.

The Build Act bars the DFC from offering subordinated loans unless a substantive policy rationale exists. These finance programs have normally provided senior debt, so subordinated debt would most likely only be considered if a compelling policy reason motivated the proposal. This new constraint is unlikely to prove restrictive as a practical matter.

Political Risk Insurance

The Build Act expands enormously the range of potential PRI coverages compared to the OPIC statute.

Under the OPIC statute, coverage had to fall within one of three baskets: expropriation, political violence or currency inconvertibility (and, as to that, covering only dividends and the proceeds from the sale of the insured business). Where variations on those themes, such as coverages against breach of contract, denial of justice or forced abandonment, were called for, the coverage had to be rooted, often through creative legal analysis, in one of the statutory authorizations. Some potentially appealing coverages could not be offered because they did not fit into any statutory box.

The Build Act, in dramatic contrast, broadly authorizes DFC to issue coverage against "any or all political risks." It then mentions currency inconvertibility and transfer restrictions, expropriation, war, terrorism, civil disturbance, breach of contract and failure to honor financial obligations as examples of what can be covered, but without limitation to those perils.

The mere fact that broader coverage is legally permissible does not mean that, as either an underwriting or policy matter, it would be wise to offer it, but where an innovative coverage makes business and policy sense, DFC is now free to offer it.

The elimination of the eligible investor restriction for insured investors is key to the reinvigoration of OPIC's political risk insurance program.

OPIC's slice of the PRI market had declined in recent years, with investors turning increasingly to the World Bank Group's Multilateral Investment Guarantee Agency or the growing private market, where no such eligibility restrictions apply. (MIGA does have its own eligibility requirements, but they are substantially less restrictive.) OPIC's eligible investor requirements were particularly problematic in large projects with a multinational sponsor group, where OPIC could support the US investors, but not the others, introducing an imbalance that complicated shareholder relationships. OPIC responded by structuring reinsurance arrangements in which ineligible investors could benefit from OPIC coverage, but those complications came at a price. Often the preferred solution was to avoid OPIC involvement in the project, undermining the effectiveness of OPIC's insurance program.

DFC's insurance authorizations are expanded not only to increase the scope of possible coverages and the relaxed eligibility requirements, but also to broaden the range of potential beneficiaries beyond the private sector. The Build Act authorizes coverage in favor of both foreign public-sector entities whose purposes are similar to the DFC and certain specified multilateral financial institutions.

That extension of eligibility could be more restrictive than it sounds. Only 12 multilateral organizations are included: four branches of the World Bank Group as well as the largest regional development banks. Dozens of smaller regional multilateral development banks are not included. These smaller MDBs often invest jointly with the listed institutions, so the limit on the new statutory authority is unfortunate. That limitation could likely be addressed in a transaction by arranging the unlisted entities as B lenders behind those authorized to receive DFC support. However, that would introduce a structuring complexity that would make deployment of DFC support more expensive. Better would be to interpret the scope of foreign public sector entities referred to in the DFC statute to include not only bilateral agencies, but also multilateral organizations.

Public-sector agency demand for political risk insurance is a recent phenomenon. Both bilateral and multilateral development banks have had the view that their character as government affiliates or associations of sovereign nations, typically including the host country, was adequate mitigation for political risks. A few projects have departed from that tradition, with DFIs seeking political risk coverage from MIGA. This provision will enable DFC also to service that market.

Investment Funds

Among the most publicized innovations in the Build Act is its authorization for DFC to make equity investments.

While Congress granted OPIC legal authority to make equity investments in the 1990s, Congressional misgivings over the appropriateness of the federal government holding ownership interests in private companies prompted Congress not to fund the program. OPIC engineered a way to provide equity support to projects indirectly. It made or guaranteed loans to private investment funds that, in turn, used the loan proceeds, together with funds invested by limited partners, */ continued page 46*

DFC

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to make equity investments in OPIC-qualified projects.

Although OPIC's investment funds program originated as an alternative to having authority to invest equity directly, having that authority will likely invigorate rather than lessen the demand for the investment funds program.

OPIC has been renamed and given enhanced authority to compete more effectively with China in emerging markets.

Melding DFI support and private limited partner funding in investment funds has proven to be an effective combination. Although OPIC was an early mover in that arena, as other agencies that were able to make equity investments joined the OPIC-supported funds as limited partners, a tension arose between OPIC and those agencies, who bristled at OPIC, who they saw as a sibling entity, enjoying superior legal rights as a lender. With equity authority, DFC is now equipped to support such ventures on terms equal with the other DFIs.

Equity authority of course also opens the door to investing equity directly into projects. Although the Build Act allows DFC to allocate up to 30% of its up-to-$60 billion portfolio to equity investments, the near-term impact of the program has been limited by the Office of Management and Budget's restrictive interpretations of that authority, which could severely restrict the supply of equity funding. DFC's current understanding is that equity investments can proceed if, as a matter of government accounting, DFC treats them as grants, with no projected recovery from the outlay and with any return counting as unexpected income. This extremely conservative approach reduces the amount of funding that might otherwise have been available, but lets the program proceed.

In a new authorization not available to OPIC, DFC is authorized not only to invest in investment funds, but also to establish and fund its own enterprise funds dedicated to making investments in commercially sound developmental activities. This authorization, which is subject to prior consultation with the Secretary of State, the Administrator of USAID and other relevant agency heads, is along the lines of an existing USAID program that traces back to the enterprise funds established for countries in eastern and central Europe in the wake of the Soviet Union's collapse. The Build Act also authorized transfer of that program to DFC, but the Trump administration has decided to keep it at USAID.

Grants

The Build Act authorizes DFC to make grants to fund the costs of feasibility studies in support of development projects. No restriction is imposed on eligibility, so they appear to be available to both private companies and prospective host governments. The terms are to include cost sharing with the grantee and providing for reimbursement of the grant if the project goes forward.

A new authority charges DFC's chief development officer, in coordination with USAID, to provide technical assistance grants, especially for small projects in "the most underdeveloped areas." DFC's support can include development of risk mitigation tools, provision of transaction structuring support, delivery of training and knowledge management tools for engaging private investors, partnering with private-sector entities that provide access to capital and expertise, and provision of technical assistance.

Although OPIC had been authorized to provide grants to microfinance and microenterprise clients, the DFC's authorizations represent a substantial increase in scope and funding.

USAID Transfers

The Build Act transferred the Development Credit Authority from USAID to the DFC.

The DCA offers partial guarantees (typically 50%, but as high as 100%) of commercial bank loans made in local currencies to qualifying borrowers in emerging markets. These guarantees are intended to encourage private lenders to extend financing to underserved borrowers in new sectors and regions.

The sovereign loan guarantee program was also transferred to

DFC from USAID, but only to administer the existing portfolio, which consists of roughly $21 billion in outstanding loan guarantees to the governments of Israel, Jordan, Iraq, Tunisia and Ukraine.

Key Policy Criteria

The DFC board, like the OPIC board, may not approve any project likely to have significant adverse environmental or social impacts unless, at least 60 days prior to the vote, an environmental impact assessment or initial environmental audit is made publicly available.

The DFC is further required to apply best practices with respect to environmental and social safeguards, and include in any contract relating to the project, provisions to ensure the mitigation of any such adverse environmental or social impacts. This states explicitly what OPIC has already required in practice. If an environmental impact assessment finds that mitigation is needed, OPIC has required that these terms be reflected in the relevant transaction agreements. DFC will do the same, whether or not the project requires board approval.

The DFC's requirements with respect to workers' rights are substantially identical to those for OPIC.

The Build Act has introduced new requirements regarding boycotts and terrorism.

The DFC must investigate whether a project it plans to support is related to any person demonstrating an intention to support a boycott against a government friendly to the United States. Further, the DFC is prohibited from supporting a government-related entity if the Secretary of State determines that the government has supported acts of international terrorism or has engaged in gross violations of internationally recognized human rights. While OPIC was required to take into account human rights and fundamental freedoms in determining whether to support a project, the Build Act requirements regarding boycotts and supporting terrorism are new.

The Build Act directs the DFC to give preference to projects falling within various categories.

However, preferences are clearly not requirements. For instance, as discussed below, there is a preference for projects involving US persons as well as a preference for projects that involve US small businesses, but the terms of the small business preference (which is a percentage of the portion of DFC projects that involve US persons) suggests that not all projects are expected to involve US persons. The impact of satisfying a preference in overcoming shortcomings of a potential project remains to be seen.

In the meantime, the Build Act provides the following six preferences.

The first involves host countries. The DFC must prioritize supporting projects in low-income and lower-middle-income countries. The DFC must "restrict" support to projects in upper-middle-income countries, unless the US president certifies to Congress that such support furthers the national economic or foreign policy interests of the United States and such support is designed to produce significant developmental outcomes or provide developmental benefits to the poorest population of such a country. DFC's interpretation of "restrict" will be important.

Although generally the Build Act expands DFC's authorities relative to those enjoyed by OPIC, the now-disfavored projects in upper-middle-income countries have been important to OPIC's operations. For instance, in fiscal year 2018 in Latin America and the Caribbean, excluding projects in upper-middle-income countries (and high-income countries, where one project was supported) would have blocked 13 of the 16 projects that were supported and all but $69.4 million of the total of $959.5 million in financings that closed (excluding regional projects). In Africa, most projects could have gone forward, but projects undertaken in Botswana and Namibia would have been blocked.

If projects in upper-middle-income countries are to be supported only on an exceptional basis, then the DFC will be significantly more constrained than OPIC with respect to where it can deploy its lending and insurance operations. However, if "restrict" were interpreted as only supporting projects with, for instance, substantial developmental benefits, OPIC could continue to play an important role in infrastructure projects in all of its traditional markets.

Small businesses are another preference. The agency is instructed to endeavor to ensure that at least 50% of DFC-supported projects that involve US persons involve US small businesses. This differs from the OPIC target of involving small businesses in 30% of all the projects it supports. Whether the DFC's small business target is higher than that of OPIC depends on whether more than 60% of DFC's projects involve US persons.

US involvement is preferred. The DFC must give preferential consideration to projects sponsored by or involving private-sector entities that are United States citizens or entities owned or controlled by United States citizens. As discussed earlier, this relaxes OPIC's traditional 25% minimum US equity requirement and the more recent requirement of a US connection. DFC's openness to supporting projects with no US private-sector involvement remains to be seen, but where other DFC goals are met, the inability to appeal to this / continued page 48

DFC

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particular preference seems unlikely to be preclusive. In fact, projects without US involvement are clearly contemplated. The small business preference is based on the portion of DFC projects that involve US persons, suggesting that not all will. In any event, DFC's ability to support projects with no US connection is a significant expansion of DFC's authority beyond that of OPIC.

The DFC is to give preferential consideration to projects in countries that comply with international trade obligations. The US Trade Representative is to provide DFC with guidance as to the countries that qualify for this preference.

The DFC must give preferential consideration to projects in countries where the government embraces economic policies that promote private enterprise, including market-based economic policies, the protection of private property rights, respect for the rule of law and combatting corruption and bribery.

Finally, women's empowerment is important. OPIC moved to support women's economic empowerment in 2018 when it hired a managing director of global women's issues, who created the "2X" initiative, an initiative to move clients in the direction of supporting women-owned, women-led and women-supporting businesses. The Build Act enshrines the agency's commitment to women's economic empowerment, and an office has been created within DFC to focus on these issues. The DFC is instructed, when providing support to projects, to consider the impact of its support on women's economic opportunities and outcomes and to prioritize the reduction of gender gaps and to maximize development impact by working to improve women's economic opportunities.

Limited Time

The Build Act provides a seven-year (from October 5, 2018) authorization for DFC to operate, but given the time required to implement the transition from OPIC, a bit more than 5.5 years remain before Congress will again need to consider and approve DFC's continuation of its activities.

Given that OPIC had been operating on year-to-year authorizations for the last several years, the seven-year authorization under the Build Act is a substantial win for the new agency and will give DFC management an opportunity to implement its new authorities without a constant threat of closure hanging over its operations.

Power Contracts and Utility Bankruptcies

by Christy Rivera in New York, and Bob Shapiro in Washington

A US appeals court made it easier in December for long-term power purchase agreements that independent generators sign with utilities to be set aside in utility bankruptcies.

An issue in such situations is who has the final word whether such a contract can be set aside: the bankruptcy court or the Federal Energy Regulatory Commission, which regulates wholesale sales of electricity.

The bankruptcy court may be more interested in eliminating burdensome purchase agreements that are weighing a utility down into bankruptcy, while the Federal Energy Regulatory Commission may be more focused on the importance of honoring contractual commitments for the healthy functioning of the wholesale power market.

A three-judge panel of the 6th circuit US court of appeals — meaning the court that hears appeals of cases in four rust belt states — said the bankruptcy court has the final word.

The appeals court said the utility does not need separately to obtain a ruling from FERC as part of its request to reject the PPA in the bankruptcy case. However, when considering the utility's request, the bankruptcy court must take into account the public-interest issues that FERC would otherwise consider if the utility were required to seek permission from FERC directly. In addition, the bankruptcy court must invite FERC to participate in the bankruptcy proceeding — the appeals court said — and to provide an advisory opinion about the requested rejection applying its standards under the Federal Power Act.

The decision is good law in the four states from the which the 6th circuit court hears appeals: Kentucky, Michigan, Ohio and Tennessee. It is not binding on the federal courts in other parts of the country.

There has been a split among the US appeals courts for the last 20 years on the issue of the supremacy of the bankruptcy court and the FERC over wholesale power contracts.

Federal courts in the 2nd circuit, which covers Connecticut, New York and Vermont, have held that FERC, not the bankruptcy court, has the ultimate authority to decide whether a wholesale power contract should be terminated. The leading decision in the 2nd circuit involved PPAs with Calpine, which had filed for bankruptcy and was trying to reject burdensome contracts.

Courts in the 5th circuit, which covers Texas, Louisiana and Mississippi, have held that the bankruptcy court has the ultimate decision. The leading decision in that circuit involved PPAs with Mirant, another bankrupt independent power company.

The issue of supremacy over power contracts arises because there are competing federal statutes that talk about exclusive jurisdiction. The Bankruptcy Code gives the bankruptcy court the exclusive jurisdiction over the bankruptcy estate, which includes contracts such as PPAs. The Federal Power Act give FERC exclusive jurisdiction over the rates at which electricity is sold in wholesale power markets, which includes PPAs. The issue of who gets the final decision on the PPAs has never been addressed by the US Supreme Court

FirstEnergy Solutions

In March 2018, FirstEnergy Solutions Corp (FES), an electricity distributor, filed for bankruptcy in Ohio and immediately asked the bankruptcy judge for a declaratory judgment that the bankruptcy court's jurisdiction trumped FERC's jurisdiction in connection with PPA rejection issues. It also asked for an injunction to prevent FERC from interfering with FES's intended rejection of certain PPAs and prohibiting FERC from evening conducting any proceedings concerning these PPAs.

FES said it had no use for the electricity provided under the PPAs it sought to reject. None of its customers, or any consumers, would be without electricity if these PPAs were rejected, it said.

Four parties to the PPAs, along with FERC, intervened in the bankruptcy proceeding. The four and FERC argued that FERC had concurrent jurisdiction and the last word on termination of power contracts.

Ultimately, the bankruptcy judge ruled that the bankruptcy court had exclusive jurisdiction over whether FES could reject PPAs, and the bankruptcy court enjoined FERC from taking any action in the case. The judge's decision was extremely broad. He not only held that FERC could not rule in a manner that was inconsistent with the bankruptcy court, but also said FERC could not even hold a hearing, collect information or express an opinion.

The bankruptcy judge said the bankruptcy court only needed to weigh the request by FES to reject power contracts under a relatively low "business-judgment" standard. This is not a difficult standard to meet. The utility must simply demonstrate that rejection of the contract at issue would benefit it in the bankruptcy case. For example, if the utility is paying above-market prices under a PPA, then it would not be difficult to demonstrate that getting rid of the PPA would help the utility re-emerge from bankruptcy.

In applying only this business-judgment standard, the bankruptcy court said it would not consider any public-interest principles that could be implicated by the Federal Power Act or any harm that rejection could cause to the independent generators with whom it has contracts or to consumers.

Appeal

FERC and the other parties appealed.

The appeals court agreed that the bankruptcy court, not FERC, had the "superior" interest in determining whether PPAs could be rejected as part of bankruptcy and therefore should be the deciding authority on the issue.

It said "the public necessity of available and functional bankruptcy relief is generally superior to the necessity of FERC's having complete or exclusive authority to regulate energy contracts and markets." With that, the court held that the decision on whether a utility can reject a PPA is to be made by the bankruptcy court alone. FERC does not have concurrent jurisdiction, meaning FERC cannot prevent rejection.

However, the court did not turn its back on FERC. The court chastised the bankruptcy court for its injunction preventing FERC from taking any actions whatsoever while the rejection issue played out in the bankruptcy case.

The court then turned to the standard of review to be used in considering whether a PPA should be rejected in bankruptcy.

It said the public-interest considerations should have received at least some attention from the bankruptcy court rather than having rejection turn solely on a "business-judgement" standard.

It held that FERC is entitled to participate in the bankruptcy case to share its opinions when rejection of a PPA otherwise subject to FERC's jurisdiction is sought. The bankruptcy court must consider the public interest, as informed by FERC, and must ensure that the equities balance in favor of rejection of the PPA — not simply that rejection of the PPA could comply with the lower business-judgment standard. But, at the end of the day, the court found that the bankruptcy law has the final say, in a manner similar to the 5th circuit in the Mirant case. In fact, the court repeatedly quoted from the Mirant decision and ignored the federal court's analysis in Calpine.

What Next?

This may not be the end of the story even in the 6th circuit.

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Bankruptcies

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On January 27, FERC and another one of the PPA counterparties filed petitions with the court of appeals asking for a rehearing by the full court — a so-called en banc review. These requests are rarely granted. The December decision was rendered by only a three-judge panel.

Whether or not rehearing en banc is granted, the parties have a right to petition for review by the US Supreme Court if the 6th circuit decision stands. Petitions for review are rarely granted by the Supreme Court. However, given the split among the various circuits, the probability that the Supreme Court would grant review is increased.

The issue of the supremacy of the Bankruptcy Code versus the Federal Power Act is an issue of current relevance in the PG&E bankruptcy. PG&E obtained a ruling from the bankruptcy court in California that would prevent FERC from exercising jurisdiction over termination of its power contracts. It now appears to be a moot point in the PG&E bankruptcy, as PG&E has agreed to assume all of its power contracts as part of its proposed restructuring plan. But that plan has not been approved yet. ◎

Environmental Update

BlackRock, the world's largest asset manager with $6.8 trillion in assets under management, declared in January that "climate risk is investment risk" and announced that sustainability will be the company's "new standard" for investing.

Larry Fink, CEO of BlackRock, made the declaration in two letters on January 14, one to corporate CEOs and the other to Blackrock's clients.

"We believe that all investors, along with regulators, insurers, and the public, need a clearer picture of how companies are managing sustainability-related questions."

Many expect the move to increase disclosure of financial risks from climate change and other environmental problems more generally. In the long term, broader disclosures about company climate risks and opportunities can be expected to affect how companies invest capital.

Fink's letter asks companies in which BlackRock invests to make disclosures aligned with the reporting frameworks of the Sustainability Accounting Standards Board and Task Force on Climate-related Financial Disclosures, or TCFD. "This should include your plan for operating under a scenario where the Paris Agreement's goal of limiting global warming to less than two degrees is fully realized, as expressed by the TCFD guidelines," Fink wrote.

Earlier in January, BlackRock also signed on to the Climate Action 100+ initiative, a global investor engagement initiative through which more than 370 investors seek to push that world's largest corporate emitters of greenhouse gases to take action on climate change.

Blackrock suggested that "a significant reallocation of capital" will take place sooner than many anticipate, in part "because capital markets pull future risk forward."

BlackRock has not supported shareholder climate resolutions in the past, and it remains uncertain whether that policy will change.

Water

The US Environmental Protection Agency and the Army Corps of Engineers proposed a new rule in January that would remove protections for certain waters in the United States.

The new "navigable waters protection rule" redefines what waters are protected by the federal Clean Water Act.

Wetlands that are not adjacent to large bodies of water, some seasonal streams that flow for only part of a year, ephemeral streams that only flow after it rains, and water that flows temporarily through underground passages would no longer be protected.

If sustained, the new rule is expected to remove federal protection for more than half of US wetlands and hundreds of thousands of small waterways. Critics worry about the potential for discharges of fertilizers, pesticides and other chemicals into those waters. The changes are being praised by farmers, developers and others who complain that broad protections imposed during the Obama administration were too burdensome.

The new rule retains federal protections for large bodies of water, larger rivers and streams that flow into them, and wetlands that lie adjacent to them.

The rule also eliminates the need to seek certain permits that were subject to regulatory assessment on a case-by-case basis.

A government advisory board of scientists responsible for evaluating the scientific integrity of EPA regulations concluded in December that the proposed water rule "neglects established science."

Many of the board's members were appointed by the Trump administration.

The scaling back of water protections will land in court. Several state's attorneys general and a number of environmental groups have said they plan to sue.

NEPA

The Trump administration proposed in January to exclude some projects, such as those that receive little federal funding, from review under the National Environmental Policy Act, or NEPA, and to impose a two-year deadline for environmental impact statements.

This is first significant revision in decades to the regulations the federal government issued to implement NEPA.

NEPA requires federal agencies to conduct detailed environmental assessments of any major federal action that could significantly affect the environment, such as by increasing air or water pollution or threatening endangered species or their habitat. Federal actions include such things as federal agency approvals of non-federal actions (such as issuing permits), federal agency funding of projects and the development of federal agency regulations.

Compliance with NEPA can be time consuming. For example, major projects with federal implications, such as pipelines, bridges, highways and power projects, usually have to wait for various federal agencies to catalog and assess potential environmental consequences. The review process can take years.

The proposed new rules would narrow the range of projects that require NEPA review.

The new rules would create a new category of federal actions that the Administration describes as having minimum federal funding or involvement. Projects in the new category could move forward without any assessment.

To help projects move faster, the new rules would also set deadlines of one year for federal agencies to complete reviews of smaller projects and two years to complete reviews of larger ones.

Perhaps the most significant change in the new proposal is language that would relieve federal agencies from having to consider the cumulative impacts of all projects as opposed to looking just at the single project being evaluated. Federal agencies have been required to consider the cumulative impacts since 1978.

A number of courts have interpreted the obligation to take into account cumulative impacts to require federal agencies to consider climate change in their NEPA reviews. While the proposed changes would not bar an agency from thinking about whether a proposed project would contribute to or help with climate change, consideration of the effects on climate change would no longer be required.

The new proposal says that federal agencies are only required to consider environmental effects that are "reasonably foreseeable" and have a "close causal relationship" with the proposed government action at issue.

The new rules will be challenged in court. A raft of lawsuits can also be expected challenging permits issued for individual projects on grounds that the agencies issuing them failed to meet their NEPA obligations.

Whether these lawsuits succeed in court may depend on the extent to which the dozen or so past rulings by courts that federal agencies must consider the cumulative impacts of agency actions relied on the old NEPA regulations, which are changing, or on the bedrock of the statute itself, which cannot be changed by agency regulation.

Another issue will be whether the impacts from upstream and downstream greenhouse gas emissions related to projects like pipelines are "reasonably / continued page 52

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foreseeable" and have a causal connection to the specific project.

Litigation could delay projects where plaintiffs claim that agencies failed to conduct a proper analysis before taking whatever federal action is at issue, such as granting a federal permit or funding a project.

Public comments on the proposed changes are currently due March 10, 2020, subject to possible extension.

Coal

Hartford Financial Services Group Inc., an insurance company, announced a new policy of excluding from coverage any companies that generate more than a quarter of their revenues from thermal coal mining or of their energy production from coal.

The Hartford also said in a December 20 news release that it will not underwrite or invest in the construction of new coal-fired power plants and will limit its association with the tar sands oil sector. It will also work to phase out existing underwriting relationships and divest publicly traded investments exceeding the new threshold by 2023.

The move continues a trend that began in Europe, but that is now expanding in the United States. Eighteen global insurers are reported to have restricted or eliminated insurance coverage for and investments in coal. The Hartford is at least the fourth US insurance company to do so. ◎

— *contributed by Andrew Skroback in New York*

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