NORTON ROSE FULBRIGHT

PROJECT FINANCE

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Tax Credits for Carbon Capture

by Keith Martin, in Washington

The market is showing early signs of a stampede to install carbon capture equipment at power plants and industrial facilities with significant carbon footprints to qualify for federal tax credits.

Some tax equity investors are circling possible carbon sequestration transactions with the aim of closing their first such transactions this year.

The US government offers a tax credit for capturing carbon emissions at industrial facilities and then doing one of three things with them. The tax credit is found in section 45Q of the US tax code.

There are deadlines to do certain things.

The tax credit amount and how long the tax credits run depend on when and how these items fall into place.

The US has 13 commercial-scale carbon capture facilities currently in operation with the capacity to capture 25 million metric tons of CO2 a year. More than 30 new projects have been announced since Congress revamped the tax credit in early 2018.

The IRS has disallowed more than half the tax credits claimed to date. The main reason is taxpayers have not been complying with the US Environmental Protection Agency requirements for monitoring, reporting and verification of the carbon emissions captured.

Qualified Emissions Source

The emissions must be from a factory, refinery, power plant or other fuel */ continued page 2*

IN OTHER NEWS

CLEAN ENERGY AND INFRASTRUCTURE will take center stage after the US Congress clears a $1.9 trillion COVID relief bill. The COVID bill is expected to move through Congress by March 15.

The closely divided House and Senate look like a recipe for gridlock, save for a process called budget reconciliation. The Democrats have potentially three cards to play over the next two years to put through economic measures by a majority vote. Otherwise, bills require 60 votes in the 100-member Senate to pass. The Senate is split 50-50 between Republicans and Democrats.

The Democrats are already in the process of playing one of the three cards to clear the COVID relief measure. */ continued page 3*

IN THIS ISSUE

1 Tax Credits for Carbon Capture
7 Cost of Capital: 2021 Outlook
18 Proxy Generation PPAs
20 Negotiating Hydrogen Contracts
25 Expected Changes in Renewable Energy Policies
32 New Trends in 2021
42 Partnership Flips
50 COVID-19 and Business Interruption Claims
52 Tapping Equity in the London Market
54 Pension Investments Bring New Opportunities and Some Challenges
57 Environmental Update

Carbon Capture

continued from page 1

combustion source, fuel cell, pipeline or manufacturing process. If the carbon dioxide is underground, drawing it out counts as long as the commercial goal is to recover some other gas mixed with it.

The facility that is the source of carbon emissions can already exist or it can be new, but any new facility must be under construction by the end of 2025. The industrial facility must normally be completed within six years after the year construction starts.

Congress extended the deadline to start construction in a tax extenders bill in late December 2020. It may do so again as part of an infrastructure bill later this year. The extensions at the front end to start construction do not affect the six-year period at the back end to finish construction.

The carbon capture equipment must also already be in place or be under construction by December 2025 or have been part of the original planning and design for the industrial facility.

The captured carbon emissions must be emissions that "would otherwise be released into the atmosphere as industrial emission[s] of greenhouse gas or lead to such release," according to the statute authorizing tax credits to be claimed. The captured emissions can be any form of carbon oxide. Although the rest of this article uses CO2 as shorthand when describing the emissions, both carbon monoxide and carbon dioxide emissions qualify.

The volume of CO2 from the emissions source each year must reach certain thresholds.

If 500,000 or fewer metric tons of CO2 are captured in a year from the emissions source, then at least 25,000 metric tons of CO2 captured that year must be put to a permitted commercial use as opposed to be being buried underground or used for enhanced oil or gas recovery.

Any power plant that does not put at least 25,000 metric tons of captured CO2 in a year to such a permitted commercial use must capture 500,000 or more metric tons of CO2 a year to qualify for tax credits.

Any other facility that does not put at least 25,000 metric tons of CO2 in a year to a permitted commercial use must capture at least 100,000 metric tons of CO2 a year to qualify.

Permitted Uses

One of three things must be done with the CO2 after it is captured.

The person capturing the CO2 can dispose of it or contract with someone else to dispose of it underground in secure geological storage. It can use the CO2 or arrange for someone else to use the CO2 as a tertiary injectant for enhanced oil or gas recovery followed by disposal in secure geological storage. Alternatively, it can put the CO2 to a permitted commercial use.

IRS regulations describe three permitted commercial uses.

The CO2 can be affixed to something else through photosynthesis or chemosynthesis, such as using it to grow algae or bacteria. It can be converted chemically into a material or compound in which the CO2 is securely stored. It can be used for some other purpose for which a commercial market exists.

Anyone putting CO2 to commercial use must do a lifecycle analysis.

The amount of CO2 considered put to commercial use cannot exceed the CO2 captured at the emissions source. It may be less. Direct and significant indirect uncaptured emissions during the full product lifecycle from production of raw inputs to delivery of the product to consumers must be subtracted. IRS regulations say that one of the lifecycle effects that must be taken into account as a potentially significant indirect effect is land use changes.

The market is showing early signs of a stampede to install carbon capture equipment.

Tax Credit Amounts

Section 45Q tax credits have been available since 2008, but they could only be claimed on the first 75 million metric tons in total CO2 sequestered nationwide.

In February 2018, Congress rewrote the statute to drop the cap, increase the credit amount, and allow tax credits to be claimed for 12 years after the capture equipment is first placed in service. (For earlier coverage, see "Tax Equity and Carbon Sequestration Credits" in the April 2018 *NewsWire*.)

An election can be made to claim tax credits on carbon capture equipment that was already in service in February 2018 under the new regime.

The following table shows the tax credit that can be claimed per metric ton of CO_2 captured at a qualified emissions source and put to a permitted use.

	CO2 put into secure geological storage	Other uses
2021	$34.81	$22.68
2022	37.85	25.15
2023	40.89	27.61
2024	43.92	30.07
2025	46.96	32.54
2026	50.00	35.00

After 2026, the amounts are adjusted for inflation as measured by the GNP implicit price deflator published by the US Department of Commerce.

A separate election can be made to treat older equipment as originally put in service on February 9, 2018 to allow a later start for the 12-year tax credit period, but only at facilities where at least 500,000 tons of CO_2 a year are being captured. However, the election cannot be made if tax credits were claimed by anyone on CO_2 captured at the facility before February 9, 2018.

Another way to buy more time is to make such extensive upgrades to the capture equipment that it is considered brand new. This starts a new 12-year period to run on the tax credits.

The amount spent on improvements must be at least four times the value of the used parts of the capture equipment that remain in use. The cost of a new pipeline to move the CO_2 to where it will be buried or used can be counted as part of the improvements if the owner of the capture equipment also owns the pipeline and uses it exclusively to transport CO_2 from the capture equipment.

If tax credits are claimed for several years after February 9, 2018 on CO_2 captured using older capture equipment that was already in place in 2018, and such extensive improvements are made in 2025 that the capture equipment is considered new, then another 12 years will start to run on tax credits in 2025.

/ continued page 4

IN OTHER NEWS

The Biden administration is still working out the details of what will be in the infrastructure package that will follow. No release date has been set yet, but releasing another $2 trillion spending plan at the same time Congress is debating whether $1.9 trillion for COVID relief is too much could complicate the prospects for both measures.

The Democrats on the House tax-writing committee released a "green" tax bill in early February that is part of the jostling to get into the infrastructure package.

The bill would extend deadlines for various types of renewable energy projects to qualify for tax credits, create a new 30% tax credit for standalone storage and also allow owners of renewable energy projects to use a quick refund process under section 6411 of the US tax code to be paid the cash value of the tax credits rather than have to barter them in the tax equity market.

It would restore the investment tax credit back to the full 30% for solar projects on which construction starts in 2021 through 2026, before starting to phase down again over the next two years, 2027 and 2028. It would push back the statutory deadline to complete solar projects to qualify for these outsized tax credits to the end of 2030.

This will lead developers to look for ways to take the position that solar projects on which construction started in 2020 were not under construction that year after all, since projects with 2020 construction starts would qualify for only a 26% investment tax credit.

Some developers may be feeling whiplash. Some scrambled at the end of 2019 to unwind constructions-start arrangements they had put in place that year for wind farms after Congress extended the deadline to start construction and increased the tax credit amount for wind farms that waited until 2020 to start construction. The same thing happened for both wind and solar developers at the end of 2020 after Congress extended */ continued page 5*

Carbon Capture

continued from page 3

Who Claims?

The tax credits belong to the person who owns the carbon capture equipment and disposes of the CO2 or contracts with someone else to do so.

The owner of the carbon capture equipment can transfer the tax credits to the company that disposes of the CO2 in secure geological storage, uses it as a tertiary injectant for enhanced oil or gas recovery or uses the CO2 in a permitted commercial use.

The election to transfer tax credits is made annually. The owner can choose whatever share of the tax credits each year it wants to transfer. The owner transfers a percentage of the total credits rather than a dollar amount. It can transfer the credits to more than one other person if more than one person will dispose of or use the CO2.

The election is made on IRS Form 8933. This is the same form used to claim tax credits and to report the volume of CO2 captured during the year. Where tax credits are assigned to the person disposing of or using the CO2, both parties must file the form, and the person disposing of or using the CO2 must attach a copy of the form filed by the capture equipment owner to its form or it will be denied tax credits.

In cases where the capture equipment owner transfers the tax credits to a company it hires to dispose of the CO2 underground, the tax credits remain with that prime disposal company even though it hires a subcontractor physically to dispose of the CO2. However, the prime disposal company claiming tax credits must hold the permit to dispose of the CO2 in secure geological storage. If the prime disposal company is a partnership, only partners who hold working interests in the partnership can share in the tax credits. The holder of a working interest shares in the cost of burying the CO2 in secure geological storage, as distinguished from the holder of a royalty interest that just shares in revenue.

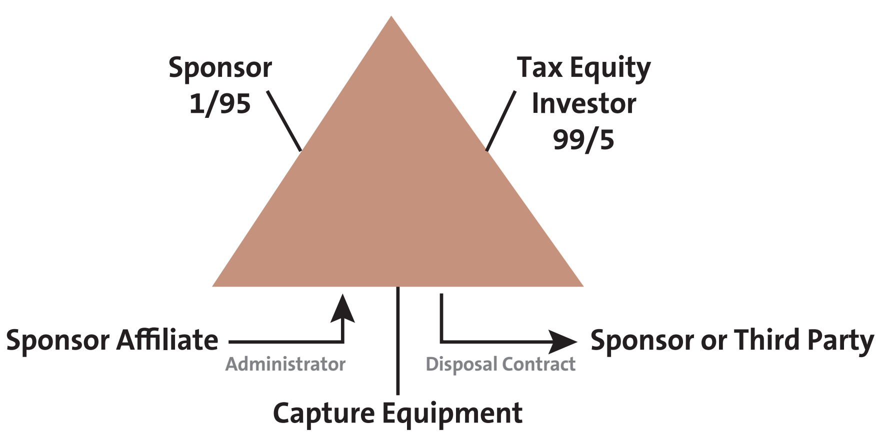
Carbon Capture Equipment

The facts that the tax credits belong to the owner of the carbon capture equipment and that the 12-year period for claiming tax credits can be restarted by making improvements place a premium on figuring out what is the carbon capture equipment.

The IRS says it is all of the equipment used to separate or capture, treat, process, dry, liquefy, pump or compress the CO2 up to the point where it is transported for disposal. The carbon capture equipment includes gathering and distribution lines that bring the captured CO2 to a central point of collection before the CO2 is transported, but it does not include the pipeline that transports the CO2.

The IRS suggested in the preamble to the final section 45Q regulations in late December 2020 that ownership of the carbon capture equipment can be split between two or more companies, but all of the tax credits belong in that case to the person who is responsible for disposing of the CO2. It is considering whether to make this clear in the regulations. The preamble said that if ownership of the capture equipment is split between two companies and both want to share in the tax credits, then they should form a partnership to own the carbon capture equipment and use the partnership agreement to allocate the tax credits to which the partnership is entitled.

Basic Partnership Flip



Tax Equity Structures

There are multiple ways to structure a tax equity deal, but partnership flip structures are expected to be the most common.

The IRS issued guidelines for carbon capture tax equity transactions that are structured as partnership flips. These guidelines can be found in Revenue Procedure 2020-12.

In a partnership flip, the owner of the industrial facility forms a partnership with a tax equity investor to own the capture equipment. Tax credits must be shared by partners in the same ratio they share in income or loss, depending on whether the partnership is expected to generate cash flow.

If the partnership activities will generate gross receipts, then the credits must be shared by partners in the same ratio that partnership income is allocated. Otherwise, they are shared in the same ratio as losses.

The tax equity investor starts with 99% of income and loss, falling to 5% after the tax credits expire. There cannot be a sponsor call option or an investor put option for the tax equity investor to exit after the flip. The parties can negotiate a repurchase of the investor's 5% interest at the time.

Less than 50% of the tax equity investment can be made on a "pay-go" basis, meaning over time as tax credits are allocated. Ongoing capital contributions to cover operating costs, like payments to a disposal company to dispose of the CO2 in secure geological storage, site lease rents, taxes and insurance, are not considered pay-go payments for purposes of the cap.

The investor must make at least 20% of its total investment when it acquires its partnership interest.

Any tax equity deal could also be structured as a sale-leaseback where the capture equipment is sold to a tax equity investor and leased back. The lease would have to require the lessee to dispose of the CO2 captured. One of several challenges with a lease structure is fluctuating rents present issues, although there is precedent in shopping center and similar commercial property leases for the lessor to take a fixed percentage of gross sales revenue as rent.

Other possible structures are an outright sale of the carbon capture equipment to the tax equity investor or a disposal contract where the tax equity investor agrees to be responsible for disposing of the CO2 but subcontracts the actual physical disposal to someone else.

The tax equity investor could also be a partner in a disposal partnership to which the capture equipment owner has elected to transfer the tax credits.

If the IRS clarifies the regulations, then other structures include a sale of the capture equipment or a tenancy-in-common structure where the industrial facility owner and the tax equity investor each own undivided interests in the capture equipment.

Some tax equity investors are using "tax event" clauses copied from refined coal deals where they will stop making capital contributions after an adverse audit adjustment or change in tax law that reduces the tax credits by more than 35%. They are also reserving the right to defer installment payments or capital contributions in up to a fixed number of quarters when the CO2 captured does not justify the full contribution.

/ continued page 6

IN OTHER NEWS

deadlines again. This time, developers wanted to buy more time to complete projects rather than claim larger tax credits. Under IRS rules, most projects must be completed within four years after the year construction starts.

The new tax credit for standalone storage would apply not only to batteries, but also to other types of storage technologies such as pumped-storage hydropower and hydrogen storage, including electrolyzers.

Another issue lurking is to what extent Congress will couple some of the new provisions to promote clean energy and infrastructure with a requirement to use union labor and American-made products. The fossil fuel industry from which the Democrats hope to transition workers is more heavily unionized. About 6% of wind industry jobs and only about 4% of solar jobs are done by union workers.

The House tax committee bill would authorize an additional 10% investment tax credit for paying the same "Davis-Bacon" wages during construction that are paid on federal construction projects and complying during construction with a series of other federal rules. Thus, it uses a carrot rather than a stick. Not all proposals do.

The US Chamber of Commerce and Bipartisan Policy Center are hoping the infrastructure package can be enacted by July 4. A more realistic timetable is sometime in the fall.

Congress may have to include significant tax increases to help reduce the net cost below $2 trillion.

Democrats are expected to increase the corporate income tax rate to between 25% and 28%, possibly as part of the infrastructure package but with a January 1, 2022 effective date. The chairman of the House tax-writing committee, Richard Neal (D-Massachusetts), said on February 12 that he does not expect a corporate rate increase until after "we have put the pandemic and recession behind us."

He said the infrastructure package is also expected to revive the / continued page 7

Carbon Capture

continued from page 5

Recapture

The tax credits claimed will be recaptured to the extent the CO_2 leaks from underground storage, including after use as a tertiary injectant for enhanced oil or gas recovery. Any tax credits recaptured must be repaid to the US Treasury

The IRS will look back three years. It assumes that once CO_2 has remained underground for at least that period, it is likely to remain underground.

The IRS has disallowed more than half the section 45Q tax credits claimed to date.

Thus, the total period when the tax equity investor claiming tax credits is exposed to some level of recapture runs potentially for 15 years: the 12-year tax credit period plus three years thereafter.

Only the net leak in a year is recaptured, meaning the leak after offsetting the CO_2 injected into the ground that year.

If multiple taxpayers are storing in the same underground reservoir, then they will have to come up with a method to allocate the leaked CO_2 among them. Leaks triggered by a volcano, earthquake (but not seismic activity caused by CO_2 injection), pandemic, war, terrorist attack or government action do not trigger recapture.

Other Issues

Carbon capture may not be economic at some facilities with large carbon footprints. For example, capture equipment and most compressors require electricity to operate. This increases the parasitic load at a power plant and may affect the economics of continuing to run the power plant. If the captured CO_2 is not relatively clean, larger compressors will be needed to compress a much larger volume of gas and the capital and operating costs may be prohibitive.

Tax equity investors will not take technology risk where new technologies are involved. They also will not take construction risk.

The potential environmental liabilities involved may make tax equity investors unwilling to be on the disposal side of the transaction.

Minimum emissions levels required to qualify for tax credits may not be reached in a year. There is a risk that coal-fired power plants will shut down before the 12 years have run on tax credits.

Cost Of Capital: 2021 Outlook

Many developers struggled during 2020 to find tax equity. Interest rates remain at historic lows. The 30-year treasury bond rate was up 24.8% through February 17 compared to year end 2020. It still stood at only 2.06%.

The cost of capital is a key factor in the price at which companies developing new power projects can afford to offer the electricity. Several thousand people registered to listen to a call among a group of veteran financiers in mid-January to learn whether finding tax equity will be any easier and hear views about the likely cost of capital this year. The following is an edited transcript.

The panelists are Jack Cargas, managing director and head of tax equity origination at Bank of America, Yale Henderson, managing director and head of energy investments at JPMorgan, Ralph Cho, co-head of power and infrastructure finance for North America for Investec, Jean-Pierre Boudrias, managing director and head of North American project finance for Goldman Sachs, and John C.S. Anderson, global head of corporate finance and infrastructure for 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 2020, and how did it break down between wind and solar?

MR. HENDERSON: It was between $17 and $18 billion, split roughly one third solar and two thirds wind. We expect the ratio between wind and solar to move even more in the direction of solar in 2021.

JPMorgan set a record in the amount of money it put into the renewables market as did, I believe, Bank of America.

MR. MARTIN: That is a remarkable figure, given that we were predicting $15 billion on this call last year. Are those numbers based on commitments made or closed deals during 2020?

MR. HENDERSON: It is a broader number. It is based on commitments as well as funded deals. There were a lot of deals that people hoped to have closed by year end, but that slipped into early 2021 and that people are still working hard to close.

The only commitments included in the number are commitments to close and fund by year end 2020. It includes such commitments where the deal slipped past the funding deadline. It does not include commitments that were originally for 2021 closings.

/ continued page 8

IN OTHER NEWS

Build America Bonds program under which tax-exempt bonds can be issued to finance public infrastructure with the bondholders having to pay taxes on the bond interest, but receiving tax credits for a fraction of the amount or else with the bond issuers receiving cash subsidy payments from the US Treasury to defray part of the interest cost. The program was available during 2009 and 2010.

The Democrats cannot afford to lose a single Democratic vote in the Senate unless they can pick up Republican votes. At least two Democrats — Joe Manchin (D-West Virginia) and Jon Tester (D-Montana) — are from fossil-fuel states. Manchin has become a key swing vote in the same way the Susan Collins (R-Maine) and Lisa Murkowski (I-Alaska) were when Republicans were in power. *The Wall Street Journal* reported that one Democratic Senator, while passing Manchin in the hall recently, greeted him with "Your Highness."

A problem with using the budget reconciliation process to pass the infrastructure package is it limits what can be included to spending and tax provisions. Some Democrats would like to include a national clean energy standard. A similar proposal failed to pass the House in 2010. Some advocates say it can be set up in form to include penalties to enforce compliance to allow it to pass muster under the budget reconciliation rules.

Another issue potentially in play is some form of price on carbon. Progressives have soured on cap-and-trade plans after similar proposals failed to pass in referenda in Democratic states.

An important issue with many Democratic constituencies is environmental justice, meaning rectifying the disproportionate effects that pollution and siting of industrial facilities have had on poor communities.

SPIRALING SHIPPING COSTS and container shortages threaten to delay construction and increase project costs.

/ continued page 9

Cost of Capital

continued from page 7

MR. MARTIN: To put these numbers into perspective, 2019 was a $12 to $13 billion year, correct?

MR. HENDERSON: It may have ended slightly higher than that, but that is close.

MR. MARTIN: Tax equity volume was $12 billion in 2018 and $10 billion in 2017. What volume do you expect this year?

MR. HENDERSON: It definitely could be in the $15-to-$18 billion range again this year, especially considering that large offshore wind projects and carbon sequestration transactions may be coming to market.

You also have to take into consideration that utility-scale solar projects are getting bigger now that they include battery energy storage systems.

MR. MARTIN: Jack Cargas, does $15 to $18 billion sound right for the coming year?

MR. CARGAS: It does. The US Energy Information Administration is predicting close to 40,000 megawatts of new wind, solar and storage capacity additions in 2021. That implies robust demand this year. We expect the main market driver will once again be supply of capital. Our prediction is that we will see similar volumes overall to what we saw in 2020.

MR. MARTIN: Yale Henderson, what percentage of the typical solar project is tax equity as we enter 2021, and what is it for wind?

MR. HENDERSON: For solar, it is 35%, plus or minus 5%. For wind, it is 65%, plus or minus 10%.

MR. MARTIN: Jack Cargas, many developers reported difficulty last year finding tax equity. On our two calls together last January and March, both of you were of the view that it would be business as usual in 2020, at least for your two banks. Yet we held two other calls, with five tax equity investors each, in May and July where some of the investors had dropped out of the market.

How would you describe current market conditions for developers wondering they will be able to find tax equity this year?

MR. CARGAS: It will be a very challenging market. Even if we hit the same volume we hit in 2020, there is so much demand for tax capacity that one wonders whether demand will outstrip supply.

The tax equity supply is difficult to forecast in the face of volatility in earnings and uncertainty around the future direction of the economy in a COVID-19 environment, the eventual scale of loan-loss provisions by banks and possible tax law changes.

MR. MARTIN: Yale Henderson, what do you say to developers who are below the first tier and who had trouble last year finding tax equity? Will they find it any easier this year?

MR. HENDERSON: Will it get easier? No. Are there opportunities for, as you said, non-first-tier but established developers to raise tax equity? Yes.

New investors enter the market to fill the void when opportunities exist. We heard of a few investors at the end of last year and early this year who are stepping up their investments, particularly in solar. Any void for capital is usually filled at some level. It may not be any easier this year, but you should be successful if you keep working hard at it.

MR. MARTIN: Get started early in the year is the best advice.

Many listeners patch into this call to get a better feel for what cost of capital to assume when bidding to supply electricity. I know you are both reluctant to talk about actual yields, so let me do it. At the start of last year, we were seeing flip yields in the range of 6.25% to 6.8% in utility-scale wind and solar tax equity transactions. Some really big developers told us they were being offered sub-6%.

Toward the end of last year, we were seeing pricing more in the 7% to 7.25% range for flip yields.

Yale Henderson, in which direction do you expect the cost of tax equity to move this year?

MR. HENDERSON: Nine times out of 10, if not 99 times out of 100, people are comparing apples to oranges when they talk flip yields across projects. There are too many variables that factor into the economics of partnership flip deals.

That said, barring any substantial change in market conditions, I don't see any reason why flip yields would change dramatically from where they were last year.

MR. MARTIN: Jack Cargas, let me ask you a different question because I suspect I will get the same answer from you on that one. You suggested before the call that there were newfound challenges in deals during 2020. What are they?

MR. CARGAS: There were at least half a dozen of significance. Let me start with two of them. One was insurance and another was force majeure.

Property and casualty insurance is becoming more challenging to obtain. The problems are lower coverage, more restrictions, higher deductibles and higher pricing. This has made tax equity investors and lenders much more cognizant of where projects are located. They are less likely to want to invest in projects in areas where hail is common or that are prone to hurricanes, earthquakes or flooding.

They want additional structural protections in the tax equity partnership documents, such as assumptions about insurance payouts in the sizing case, different cash sweep or step-up mechanisms or perhaps more reliance on corporate fleet-wide insurance programs to spread the risk and the coverage and costs.

In 2020, many force majeure notices were issued to sponsors by equipment suppliers and construction contractors. Many of the notices appeared to be defensive in nature and blamed COVID. Many of the claims were rejected by sponsors.

It was unclear in most cases what claimants were trying to get out of these notices — delayed delivery dates, decreased liquidated damages? Many claims just became an unnecessary distraction. The question remains what happens with these force majeure notices going forward? Is COVID-19 a pre-existing condition and, therefore, not a subject for force majeure? It is something that we are watching closely.

MR. MARTIN: Yale Henderson, anything to add to that list?

MR. HENDERSON: Yes. We are concerned about the size of the tax basis step-ups that we are seeing sponsors demand in their requests for proposals from tax equity investors.

We also see a continuing underestimation of electricity basis risk by sponsors in the base case models they send us. This has an effect on the ultimate revenue profiles for projects. We encourage them to hire competent consultants to help with a realistic forecast and then to make sure it is properly reflected in the model.

Batteries will obviously be big this year, particularly as developers see opportunities to use them to arbitrage peak pricing and add revenue. Getting credible estimates of what those ancillary revenues will be, how long they will last and at what level will be important.

Finally, commitment periods are getting longer, and that is contributing to some of the issues with tax equity supply. The market is moving toward commitment periods as long as 18 months to two years. However, when tax equity gets committed that far in advance, it puts stress on the ability to handle current market opportunities. It may be harder for sponsors that do not have deep banking relationships to compete for tax equity in such a market.

MR. MARTIN: Jack Cargas, are you looking at carbon capture?

MR. CARGAS: Yes. It is nice to see that the IRS issued the final regulations on section 45Q tax credits in December. Carbon capture projects will be in direct competition for tax equity with offshore wind, onshore wind, utility-scale solar, residential solar and other types of renewable energy / continued page 10

IN OTHER NEWS

Shipping costs to move goods from Asia to the US West Coast were up 190% year on year through December. Costs from China to Europe are up four times in the last eight weeks. More containers are now being returned empty to China rather than wait to load them at US ports because almost 10 times as much can be earned by using them to carry goods from China to the US rather than vice versa.

Port congestion is also contributing to shipping delays. In early February, a record 36 container ships were sitting on anchor outside the port in Los Angeles waiting to unload while another two were waiting at sea for anchorages to open.

UIGHUR issues are starting to play a role in financings.

The New York Times reported on January 9 about the possibility that Uighur labor is being used to make polysilicon or solar panels made by five Chinese solar panel suppliers. The five are GCL-Poly, East Hope Group, Daqo New Energy, Xinte Energy and Jinko Solar.

The US banned cotton and tomatoes imported from the Xinjiang region in western China in January.

The House voted nearly unanimously in September to ban "all goods, wares, articles, and merchandise mined, produced, or manufactured wholly or in part" in Xinjiang, unless US Customs can be persuaded by "clear and convincing evidence" that the products were not made with forced labor by Uighur Muslims. The bill failed to pass the Senate at year end after lobbying by apparel and technology companies concerned about the difficulty of tracing supply chains.

A bipartisan group of 29 Senators reintroduced the bill in late January.

Banned goods would be subject to seizure at the US border.

Solar companies have been trying to diversify supply chains to avoid potentially affected products. The Solar / continued page 11

Cost of Capital

continued from page 9

projects. We are watching the carbon capture market develop and are beginning to see some real opportunities.

MR. MARTIN: Yale, are you looking at carbon capture as well?

MR. HENDERSON: Yes. We expect to make an investment in such a project in the not-too-distant future.

MR. MARTIN: Jack, have your investment parameters changed as we enter 2021 and, if so, how?

Renewable energy tax equity was a $17 to $18 billion market in 2020.

MR. CARGAS: Yes, in at least three ways. We examine the overall bank relationship, both historical and prospective, with our sponsors. We look hard at project quality and geography. And we focus on the sponsor's ability to execute the trade efficiently. We delivered on every one of our tax equity commitments at Bank of America in 2020, and we expect to do the same in 2021.

MR. MARTIN: These parameters do not seem like a change. Has anything changed?

MR. CARGAS: There is more focus on the overall bank relationship.

MR. MARTIN: Yale, has there been any change in your investment parameters?

MR. HENDERSON: No. We scroll through a list of factors when deciding whether to pursue a particular transaction. The items on that list have not changed in a meaningful way in the last year.

MR. MARTIN: I think you were expecting to end up with about $4.5 billion in total tax equity investments last year. Is that where you in fact ended up?

MR. HENDERSON: We exceeded that number.

MR. MARTIN: Jack Cargas, where did Bank of America end up?

MR. CARGAS: We also exceeded that number.

MR. MARTIN: Are there any other noteworthy developments in the tax equity market?

MR. CARGAS: We completed our first large combined-resource partnerships in 2020. Combining wind and solar makes a lot of sense due to complementary resource characteristics and complementary tax credit characteristics. Sponsors like it for those reasons and because it can make for better upstream financing packages or better sponsor cash equity sale packages.

MR. MARTIN: Does that mean you have a tax equity partnership where the tax equity investor is claiming both investment tax credits and production tax credits?

MR. CARGAS: That's right.

We have done more than one of those partnerships. We also completed our first large-scale battery partnership in 2020, so that transaction grammar is in place, too.

MR. MARTIN: Yale, other noteworthy developments?

MR. HENDERSON: We did transactions last year with the same profiles.

COVID forced investors to become more efficient at executing transactions. One example is how they do engineering diligence. When our engineers can watch a time-lapse video of a foundation pour, they feel they have a better understanding how things are going, and it increases our comfort level that things are being done appropriately at every site and on every foundation pour and every turbine built. This is just one of many ways we are all having to adapt because of restricted travel and lockdowns, but that are leading to efficiency gains in how investors transact.

Bank Debt

MR. MARTIN: So there is an upside.

Let's move to Ralph Cho on bank debt. Has the bank market settled back into its pre-COVID pattern and, if not, what are the lingering effects?

MR. CHO: Last year was a roller-coaster year. It started off pretty strong during the first quarter. It quickly came to a halt in March and April when everyone started working from home.

I remember having a call just like this with you around that time when everything was falling off a cliff. There was a spike in bank lending costs. Spreads increased by 25 to 50 basis points. The banks at that point were just basically wrapping up deals that were already in process without making new commitments. Any bank that was wider than that level was effectively shut out.

But the bank markets are resilient. By summer, funding costs had fallen back in line with pre-COVID levels and, in some cases, they had even improved.

As for lingering effects, the bank markets are still liquid, but choppy. Not all the capital sources with whom we work are back at the table. For example, we have not seen the South Korean lenders come back at the same level of appetite as pre-COVID. Credit committees in general are still sensitive to COVID-related risks. Construction risk, demand risk and operating risks are all being analyzed carefully.

MR. MARTIN: What was the deal volume in the North American project finance bank debt market last year compared to 2019?

MR. CHO: It was better than expected. The latest preliminary data from Refinitiv — and that will be finalized at the end of the month — suggest that North American bank volumes were up more than 12% from 2019. Total volume was $69.5 billion for 2020 versus $62 billion in 2019. Given that the market was shut down during March and April, this is a remarkable result. The total deal count was around 213.

MR. MARTIN: There were 220 deals in 2019.

MR. CHO: Correct, so down slightly.

MR. MARTIN: How many active banks are there currently in the market?

MR. CHO: We saw roughly 50 to 70 lenders last year, with perhaps 30 to 40 highly active.

We have heard various reasons for this, including that people were uncomfortable about the potential impact of COVID in the US. Some lenders with long underwritten positions have been unable to sell. Some lost money from loans that have defaulted. Another issue has been the difficulty doing site visits and other physical due diligence.

Lenders are more likely to be able to participate in refinancings than in wholly new transactions.

We have also seen a number of tier-2 and tier-3 retail banks go on pause for now because their credit committees are researching their portfolios and are */ continued page 12*

IN OTHER NEWS

Energy Industries Association said it is working to create traceability protocols for the industry that it expects to release before the end of March.

PENSION PLANS may soon find it easier to make ESG investments.

After only several hours in office, the Biden administration took steps to roll back recent Trump administration limits on environmental, social and governance investments by US pension plans.

The Trump administration proposed barring pension plan investment managers from considering ESG factors, or investing in funds set up to make ESG investments, if the effect is to sacrifice return or take increased risk. The department made the proposal in July 2020 and then finalized it in early November, despite receiving 8,700 comments of which 95% were opposed to the new approach.

The prohibition took effect on January 12, 2021.

Biden immediately suspended it in an executive order listing regulations and other actions taken by the Trump administration in the last four years that conflict with his new policy priorities, including tackling climate change. The pension ESG regulation was the only US Department of Labor regulation called out for review.

Marjorie Glover, a pension and executive compensation expert in the Norton Rose Fulbright office in New York, said opponents of the ESG regulation are hoping that Biden will either withdraw or replace the ESG rule or issue guidance clarifying that ESG goals are pecuniary factors that may be considered by pension plan actuaries and that sustainable investment funds may be included as 401(k) plan default investments.

Although pension plans have the potential to become an important source of funding for renewable energy, projects accepting pension plan money must be */ continued page 13*

Cost of Capital

continued from page 11

reluctant to add new projects during the pandemic.

This loss of liquidity was counterbalanced by the entry of some newer players in the form of credit and debt funds, albeit coming in at a slightly higher cost of capital. My expectation is we will see some of the sidelined capital creep back into the market this year.

MR. MARTIN: In the last two years, there were 80 to 100 banks and grey-market lenders chasing deals, so there has been at least a 30% drop in number.

What is the current spread above LIBOR for bank debt?

MR. CHO: We saw a lot of deal flow come back like crazy in the second half of last year. Plain-vanilla loans — and I am including back-levered renewables deals — are pricing at LIBOR plus 125 to 137.5 basis points. Short-term construction bridge loans are probably pricing around LIBOR plus 90 basis points. Depending on the size, you could probably go tighter, but 90 basis points is where most of the action is currently. Construction bridge loans that could go up to 24 months are pricing at a slight premium at 100 to 125 basis points over LIBOR. Greenfield quasi-merchant gas projects are probably going out at LIBOR plus 350.

The low cost of funds for banks is keeping their senior pricing tight, as you can see from the numbers. Grey-market lenders do not have the same flexibility. They just try to take a little bit extra risk to get their limited partners the returns they have been promised. Returns for grey-market lenders can vary anywhere from 6% to 12%, depending on the type of debt fund.

Grey-market lenders are buying up stretched senior and holdco paper. If you are a borrower looking for this type of capital, the sweet spot is probably around LIBOR plus 400 to 450 basis points. There are always exceptions where a borrower may end up with spreads a little tighter or a little wider, depending on the project and how much it is trying to borrow.

MR. MARTIN: The 400 to 450 basis points is for debt that is subordinated to other, senior or back-levered debt, correct?

MR. CHO: Yes.

MR. MARTIN: Is there a LIBOR floor currently in the bank market?

MR. CHO: Not really. If there is one, it would probably be 0%. There is a LIBOR floor in most grey-market loans of 1%.

MR. MARTIN: What upfront fee should one expect on a bank loan?

MR. CHO: Such fees generally range anywhere from 100 to 200 basis points in the bank market, based on whether the loan is wholesale or retail. We usually tier the fee based on the size of commitment and whether the loan is being underwritten and syndicated. If the loan will be syndicated, then that tends to push the fee out to 200.

MR. MARTIN: Are there commitment fees on top of that?

MR. CHO: Yes. A commitment fee of 50 to 75 basis points is charged on the undrawn loan commitment or unused letter-of-credit commitment in place of the full LIBOR plus margin on that part of the debt.

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

MR. CHO: For wind, they are generally 1.35 times the P50 revenue forecast. Solar is probably tighter at 1.25 times P50. Solar projects have a lower standard deviation on resource forecasts, so the forecast is a little more reliable.

In the past, lenders usually only credited contracted cash flows for purposes of debt sizing. In order to compete today, lenders are crediting up to five years of post-PPA revenue. Thus, even though they are taking some merchant exposure on the back end, commercial banks are still pricing as if these were plain-vanilla loans. That tells you something about the competition for deals.

Many developers will find it challenging to raise tax equity this year.

To be competitive, the debt on contracted gas-fired assets would have to be sized about 1.3 times revenue available for debt service over the life of the power contract. There are not many contracted gas-fired assets coming to market, so any such deals attract a lot of competition. Quasi-merchant gas deals are a little more complicated. We size the capacity and energy payments at around 1.5 times.

We have been using flat-lined capacity forecasts in areas like PJM and New England. We've seen increased usage of the cross-commodity netback hedges. We size these cash flows at around 1.5 times, based on a conservative case. Lenders are open to giving credit on conservative merchant energy revenue forecasts at around 2 to 2.5 times. One issue is how much of the debt principal will remain to be repaid at maturity on the bank loan. The answer depends on the location, the age of the project and the technology.

MR. MARTIN: Has there been any change in the typical loan tenor since last year?

MR. CHO: No. Typical loans are structured as five- to seven-year mini-perms, particularly for refinancings and some acquisition debt. That is construction plus five years if there is a construction element to it.

We have seen tenors for some plain-vanilla financings go over 15 years, assuming a long-term power purchase agreement, especially in the renewables sector.

We have heard rumors that some Canadian renewables borrowers can put pressure on their banks to go up to 19 years by threatening to take the debt to the project bond market. However, these offers are more like unicorns; they are hard to come by. They are probably reserved for tier-1 relationship borrowers.

MR. MARTIN: I was going to ask if you have seen any change in appetite among banks for different types of projects — for example, quasi-merchant projects, projects with corporate PPAs or CCA contracts, community solar projects, standalone storage facilities — but I suspect the answer is multiple banks will be interested.

MR. CHO: There is strong interest from banks in supporting all ESG-class assets. Appetite for such assets has increased at every level of the capital stack. ESG investors are willing to take lower returns and higher risk for such assets. They see ESG as the primary driver, and economics are the secondary driver.

There is diminished appetite for merchant gas projects in PJM where the capacity auctions have been delayed a couple times and spark spreads are pretty much crap. However, if borrowers are willing to take a conservative view on capacity forecasts, banks have an appetite to lend.

MR. MARTIN: Are there any other / continued page 14

IN OTHER NEWS

careful to work around tax rules that deny investment tax credits and accelerated depreciation to projects to the extent they are owned by government or tax-exempt entities and to avoid becoming "plan assets" that could subject the projects to burdensome legal obligations under a 1974 law called the Employee Retirement and Income Security Act or ERISA. (For more detail, see "Pension Investments Bring New Opportunities and Some Challenges" in the February 2021 *NewsWire*.)

BATTERY MANUFACTURER SK Innovation will be barred from importing battery components into the United States for 10 years under a US International Trade Commission decision in early February.

The ruling is the latest action in a skirmish between SK Innovation and LG Chem, two South Korean battery makers that also have US operations.

LG Chem accuses SK Innovations of stealing employees and intellectual property.

Section 337 of the Tariff Act of 1930 gives the US International Trade Commission authority to block imported goods that benefit from unfair trade practices. For example, the section has been used to block imitation brand-name goods that violate US patents or copyrights.

President Biden has 60 days to reject the decision. SK Innovation can appeal after that to the US court of appeals.

TAX INSURANCE premiums may not be deductible.

The IRS disallowed deductions claimed by two partnerships on grounds that the insurance was not closely enough related to each partnership's business to be an "ordinary and necessary" business expense, according to internal IRS memoranda made public in December. / continued page 15

Cost of Capital

continued from page 13

noteworthy trends as we enter 2021?

MR. CHO: Yes.

ESG will remain front and center, especially for lenders across the capital stack and especially when it comes to the energy transition. These financings attract a lot of lenders: commercial banks, credit funds, private equity investors. It clearly shows because you see the returns being beaten down. It will be interesting to see whether more capital is willing to fund before notice has been given to proceed with construction, especially at a friendly cost of capital.

Ted Brandt from Marathon Capital talked on a panel you moderated last week at the Infocast Projects & Money conference about leveraged equity returns coming in at something like 6% on ESG projects. That is remarkable. When we take syndicated deals to market, an ESG asset gets twice the interest.

Digital infrastructure is also going to be hot. My UK counterparts have been active in this market. We polled a lot of bankers about the sectors on which they want to concentrate in 2021. Our polls show 22% want to be in digital infrastructure and 57% say ESG.

PJM activity should hopefully pick up this year after being quiet last year. Two capacity auctions are expected finally this year. Some developers with existing projects are hoping to refinance this year.

Lastly, I think that capital sources will remain frothy. South Korean lenders sat largely on the sidelines last year. I think they will move slowly back into our system. Some of them are sending more bankers from Seoul to New York. They are here now physically and beefing up their local presence. That is a sign they want to be more active here.

Don't forget about capital that limited partners are investing in blind credit funds. We expect to see more of that this year.

Term Loan B

MR. MARTIN: Let's move next to Jean-Pierre Boudrias from Goldman Sachs and the term loan B market. Term loan B debt is debt using bank papers, but placed with institutional lenders. It tends to be lighter on covenants. It is often used for riskier projects.

J-P, the term loan B market reacts more quickly than the bank market to changing market conditions. Shortly after the COVID lockdowns started last March, the average B loan debt instrument was trading at only 76¢ per dollar of face amount, which implied a 625-basis-point spread over LIBOR and about an 11% coupon rate. Loans to independent power projects held a little more of their value, maybe 80¢ to 83¢ on the dollar. The market was pretty deeply dislocated. Has it recovered fully?

MR. BOUDRIAS: The B loan market has recovered. The investment-grade bond market was the first to recover. The loan market took a little longer, but the S&P LSTA Index shows the average B loan trading at 97.5% of face amount. That works out to around a little over 400 basis points over LIBOR.

When we had this call last year, about 60% of loans were trading at par or above par. Obviously, that went to zero in the March and April time frame and stayed there for a few months. Now we have slowly recovered and are now at the 40% mark. As a result, you are seeing the first wave of re-pricings coming to market across various sectors.

MR. MARTIN: That is 40% of B loans are still trading below par?

MR. BOUDRIAS: No, 40% are trading at par or above.

MR. MARTIN: Got it. What was the term loan B volume in the North American power sector in 2020, and how did that volume compare to 2019?

MR. BOUDRIAS: In 2020, we saw seven transactions for a total of $5.5 billion. In 2019, volume was about $4.6 billion. It was a small increase, but it was probably transaction-driven in terms of what deals came to market and when.

MR. MARTIN: What types of deals were the seven?

MR. BOUDRIAS: There was only one acquisition financing. Most of the rest were refinancings or amend-and-extend transactions, which means amending the existing debt papers to push the maturity out by a year or two. There were one and a half repricing deals because one of the deals was an amend and extend, but also got repriced. It was launched as a repricing originally.

MR. MARTIN: Were any of these deals renewables?

MR. BOUDRIAS: There was one renewable energy transaction that was a refinancing late last year.

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

MR. BOUDRIAS: We expect about $3 billion to go to market to refinance existing transactions. We expect to see deals that will get repriced, so we will get some volume there. There are also acquisition financings expected to come to market. My suspicion is that we will probably have a $9 to $10 billion year in 2021.

MR. MARTIN: Pricing a year ago for strong BB credits was about 350 to 375 basis points over LIBOR. You were expecting at the start of the year for pricing to fall below 300 basis points, but that obviously did not happen after COVID hit. A single B borrower could expect to pay 400 to 425 points over LIBOR. Where do you see rates today?

MR. BOUDRIAS: We probably ended 2020 where we started, but since the beginning of 2021, we probably gained a bit.

A BB credit is probably pricing around 325 or 350 basis points over LIBOR today with an ability to outperform if trends continue the way they are. With a single B credit, the range is probably wider at 375 to 425.

There has been some differentiation in credit. When I talk about the average bid of 97.5% for the outstanding paper on single-asset power deals, it is important to understand there is a range. Some price above this. A number have not recovered yet and are still in the mid-90% range. The power market where the project operates is an important factor.

MR. MARTIN: When you say "outperform," from whose perspective are you speaking?

MR. BOUDRIAS: The borrower. I think there is a possibility that spreads will narrow as we move further into 2021.

MR. MARTIN: B loan debt has been sized historically at six to six and a half times projected EBITDA with at least 50% repayment of loan principal required over seven years and a loan-to-value ratio of 75%. Has there been any change in these metrics?

MR. BOUDRIAS: Not really. We tend to see these metrics in acquisition debt. There was only one acquisition financing last year.

MR. MARTIN: What are the metrics for other types of B loans?

MR. BOUDRIAS: It will vary based on ratings aspirations, but we tend to see four to six times leverage for BB and B, respectively.

MR. MARTIN: Loans as small as $225 to $250 million can be placed with B loan lenders, but there is a steep drop off in liquidity once a loan size falls below $500 million. One of the new trends you cited last year was the arrival of direct lenders who are doing deals as small as $125 to $200 million. Are they still in the market? Are there other new trends as we enter 2021?

MR. BOUDRIAS: The direct lender trend is still there. I don't think we really see any other new trends. Obviously, as volume builds throughout the year, we may see other new developments.

I would like to remind listeners the total B loan volume in our sector is about $17 billion out of $1.2 trillion for the B loan market as a whole, so it is a rather small segment. Often, our sector benefits from trends that start in other market segments and make their way to the power world. / continued page 16

IN OTHER NEWS

The memoranda are CCA 202050015 and ILM 202053010.

In one of the cases, a private placement memorandum was issued to raise capital from investors to buy a piece of land that the private placement memorandum said would either be developed, held for investment, or preserved by donating a conservation easement to a nature conservancy and then claiming a charitable contribution deduction.

The partnership did the latter. It also bought tax insurance against which investors could make a claim if the IRS disallowed the deduction for the charitable contribution.

The IRS said the tax insurance premiums were not deductible because the insurance was unrelated to the trade or business of the partnership.

The other case appears to involve similar facts.

The IRS has been fighting syndicated conservation easement tax shelters in court.

THE TRUMP BULK-POWER SYSTEM executive order has been suspended for 90 days as part of a day-one executive order that President Biden signed immediately upon taking office on January 25.

The suspension also extends to a prohibition order that the US Department of Energy issued in December barring the purchase of Chinese-made transformers and related equipment by utilities serving critical defense facilities.

Neither order is expected to be reinstated in its current form.

The May 1 Trump executive order barred power companies from buying, using or transferring any equipment supplied by foreign adversary companies that could be used to harm the US power grid.

The US Department of Energy used the authority in the executive order to issue its own order in mid-December prohibiting any "responsible utility" / continued page 17

Cost of Capital

continued from page 15

Project Bonds

MR. MARTIN: Let's move to John Anderson and project bonds. Project bonds are long-term fixed-rate loans. The loan tenor can be as long as 30+ years. The rates are fixed for the full duration. The bonds are issued at a spread above current treasury bond rates. Is it 10-year or 30-year treasury bonds?

MR. ANDERSON: The 10-year treasury is the usual benchmark. For a project with a 20-year power purchase agreement, the debt will have an average life of about 12 years, so the 10-year treasury is the best place to focus.

MR. MARTIN: Last January, you said contracted projects were clearing at spreads about 175 to 190 over 10-year treasuries. That translated into a coupon rate of about 3.5% to 3.75%, but by late March after the COVID lockdowns, the spreads had jumped by 200 to 300 basis points. The market has since settled. Where is it today?

MR. ANDERSON: Good news for borrowers in this area. On the spread component, we have really come full circle, back to the 175 to 190 range, and maybe even slightly lower in the US in certain situations. The really nice thing for borrowers is that base rate, the 10-year treasury, has come down from just under 2% a year ago to just over 1% today. Put all of that together into an all-in interest rate, and the widest you would have paid a year ago was a coupon rate of more than 4%. Today, you can get 3% and maybe a touch inside.

MR. MARTIN: Is COVID having any lingering effects?

MR. ANDERSON: Despite the K-shaped recovery and the uneven impact of COVID on the economy, infrastructure, power and clean energy are really motoring ahead. These are essential industries. There is strong demand from investors.

People have talked on this call about some of the remote working techniques to which they have had to adapt. That is true in the project bond market as well.

Insurance companies and financial investors drive the investment-grade bond and private placement markets. ESG and climate change are dominating the conversations today. We see that in the broader bond market, too. If something has a green tag on it, people will definitely look at it with greater interest. We don't see a premium being paid for green paper, but investors definitely are interested in it.

MR. MARTIN: Let's talk about volume. The syndicated US dollar denominated project bond market was stable at $100 billion a year in each of 2018 and 2019. What was it in 2020?

MR. ANDERSON: It was at least that or slightly higher. That's because the clean energy transition continues apace, and we were not disrupted like speculative-grade lending or some other sectors of the economy.

Sometimes we talk about project finance and its share of the broad market. That measure is a bit of a head fake. The project finance share of the broad market went down because the broad market expanded so much. Thus, if you looked at the US dollar investment-grade bond market last year, it went from $1.1 trillion in 2019, which was a pretty good year, to $1.8 trillion last year. The broad market was up by 63% as corporates went after liquidity. We had issuances by such borrowers as hospitals, universities and foundations that do not normally come to market. The denominator was a lot bigger, but infrastructure and projects were still a great place to invest. Maybe they were a smaller share because other issuers were tapping into emergency funding.

MR. MARTIN: What was the numerator for projects and infrastructure?

MR. ANDERSON: We are not a market maker, so I don't track that, but as an investor it felt like we were up in volume similar to the 12% increase that Ralph Cho said he saw last year in the bank market.

MR. MARTIN: You have said in the past that 19% to 20% of the market is infrastructure and projects, including power. How many syndicated deals are in the pipeline today at the start of the year?

> The market is turning away from projects in areas with hail, hurricanes, earthquakes or flooding.

MR. ANDERSON: We see between three and five deals in the market at this point which is a little lighter than we saw at this point last year. We had such a low cost of debt last year that maybe people were front running the market a bit.

MR. MARTIN: You are a direct lender. You don't place deals in the syndicated market. Project bonds work for direct loans as small as $25 million, while loans in the syndicated market need to be at least $250 million. Has COVID affected either metric?

MR. ANDERSON: That has been pretty stable. You can find a lender to work with you on something bilaterally at $25 to $50 million, but to get a good syndication going, you probably do need to be at least $250 million.

In between, your arranger will help you with a club-type of approach where maybe if you are raising $100 million, the arranger will go out to three or four investors and your direct lender, like Manulife, will act as the anchor. Most of the individual lenders who will do $25 to $50 million as part of a club will also do $100 or $150 million with you bilaterally.

MR. MARTIN: Let's run down the main differences between project bonds and other types of debt quickly. You deal with insurance companies and other institutional lenders as opposed to the banks. Project bonds generally have the same tenor as the power purchase agreement. There is no up-front fee for a project bond because the economics are baked into the spread. Ratings may be required for widely syndicated deals, but not for private or direct placements. Make-whole payments are required if bonds are repaid ahead of schedule. Such payments are not required in the bank market, but there may be a prepayment penalty. The project bond market takes construction risk and will charge a commitment fee on drawn capital. Is all of this accurate?

MR. ANDERSON: It is. We are the long cheap money so we really shine when you have a long-tenor PPA. People will work on shorter-duration bonds, as well. There is strong investor demand to deploy this year. Infrastructure portfolios held up very well in 2020. We were experiencing significantly lower default rates than other sectors of the economy, so that is a tailwind for us as we move into 2021.

MR. MARTIN: Are there any other noteworthy trends as we enter 2021?

MR. ANDERSON: The tailwind from the government. Investor interest in ESG transactions is also a tailwind. Investors have a lot of capital this year to deploy. Maybe we will see some tightening of spreads along the way. ◎

IN OTHER NEWS

from acquiring, importing, transferring or installing certain Chinese equipment that is considered to come in contact with parts of the US utility grid that serve critical defense facilities.

The department sent notices to the affected utilities within five days after the prohibition order was issued.

The affected equipment is utility transformers with a low-side voltage of 69 KV and generator step-up transformers with a high-side voltage of 69 KV and associated control and protective equipment such as load tap changers, cooling systems and sudden pressure relays, circuit breakers operating at 69 KV or higher, reactors and capacitors at 69 KV or higher and associated software.

The order applies to any prohibited transaction initiated on or after January 16, 2021.

The affected equipment is equipment "manufactured or supplied by persons owned by, controlled by, or subject to the jurisdiction or direction of" the People's Republic of China.

The department said it has determined that China is "equipped and actively planning to undermine" the US electricity grid as part of "system destruction warfare" aimed at crippling the ability of an opponent to respond at the start of any conflict.

It said Chinese companies providing goods to critical US supply chains can be compelled under Chinese law to provide intelligence to the Chinese government.

Each affected utility was supposed to notify the US Department of Energy by February 15 that it had taken steps to ensure that critical US defense facilities will retain priority status during periods the utility must shed electricity load, meaning temporarily cut off customers.

Each affected utility must certify to the department by March 17, 2021 and every three years thereafter that it has not entered into any prohibited transactions and that it has an internal monitoring process to track compliance with the order. */ continued page 19*

Proxy Generation PPAs

by Christine Brozynski, in New York

Power purchase agreements that settle based on "proxy generation" are becoming more common for wind and solar projects.

Such power contracts are a variation on a type of hedge called a "contract for differences." The contract has a "strike price."

If the actual price the owner of a power project receives for any given megawatt hour of electricity sold is greater than the strike price, then the project owner pays the excess to the hedge provider. If the actual price of electricity is lower than the strike price, then the hedge provider pays the difference to the project owner.

PPAs that settle on proxy generation are becoming more common.

In most renewables projects, a contract for differences settles based on the amount of power actually produced by the project during the settlement period rather than a fixed notional output quantity.

The main difference between a proxy generation PPA and a typical contract for differences is that the proxy generation PPA settles based on the "proxy generation" rather than the actual output of the project.

"Proxy generation" means the amount of power the project would have produced if the wind turbines or solar panels had operated at an assumed rate of efficiency. The rate of efficiency is negotiated between the hedge provider and developer before execution of the proxy generation PPA documents.

For example, the owner of a wind project might negotiate a proxy generation PPA with an efficiency rate per turbine of 85%. A third party, called the calculation agent — often REsurety, the company that invented the proxy revenue swap — measures the actual wind at each turbine during the settlement period and then uses this to recalculate the amount of power the turbine would have produced had the turbine been operating at 85% efficiency.

Calculations

The actual calculations are very complicated as many elements of the turbine's operation must be assumed.

The result of the calculation is that the developer assumes the operating risk at the project. If the turbines operate ultimately at 75% efficiency rather than 85% efficiency during a given settlement period, then the developer is not entitled to a payment from the hedge provider to make up for the lower amount of power produced. The hedge will still settle as if the project had produced the amount of power that would have been produced by turbines operating at 85% efficiency. The hedge settles based on actual output as adjusted for the proxy generation.

On the other hand, if the turbines actually operate at 95% efficiency for a given settlement period, the developer is not required to give that excess to the hedge provider.

The calculations for solar projects are often less laborious (albeit still complicated) than the corresponding calculations for wind.

Often parties will rely on a weather model with granular data on the actual amount of irradiance at the project site during a given settlement period. As a result, there is no need to collect actual project data. The calculation agent uses the irradiance amount from the weather model to determine the amount of power that would have been produced had the panels operated at the assumed rate of efficiency.

Despite the similar name, proxy generation PPAs are different from proxy revenue swaps.

Both products rely on the proxy generation rather than actual generation at a project. However, proxy revenue swaps do not use a strike price per megawatt hour of power. Rather, the hedge settles based on a fixed lump sum per settlement period negotiated before execution of the hedge.

If the "proxy revenue," or amount of revenue the project would have earned based on the proxy generation rather than actual output, exceeds the lump sum for a given settlement period, then the developer pays the excess to the hedge provider. If the proxy revenue for the settlement period is less than the lump sum, then the hedge provider pays the difference to the project.

Proxy generation PPAs are usually documented on an International Swaps and Derivatives Association form, similar to many hedges.

Key Issues

Developers should be aware of a few key items in the proxy generation PPA.

First, the hedge starts settling on a set date, regardless of whether the project has commenced commercial operation by that date. This is feasible because the contract relies on "proxy generation" rather than actual generation, and proxy generation can be calculated without actual project data. This is especially true for solar projects, where the weather model provides all of the data necessary for the settlement calculation. For wind projects, the calculation agent uses relevant wind data to determine the settlement.

This can be unsettling because the project may not have a source of revenue yet to make any required hedge payments. Developers address this problem by making sure that there is sufficient cushion between the anticipated commercial operation date and the hedge start date. If the hedge nevertheless starts settling before commercial operation, then developers may need to contribute equity to the project to make payments. Otherwise, the hedge provider will draw on the credit support.

Second, the hedge typically contains a deadline for commercial operation. If the commercial operation date does not occur by this deadline, then the hedge provider usually has a termination right. Usually the deadline is either on the date the hedge starts settling or several months after.

This can complicate raising construction debt because construction lenders count in the worst case on the project still being able to operate and earn revenue even / continued page 20

IN OTHER NEWS

STORAGE is expected to account for 11% of new capacity additions this year in the United States, reflecting a rapid rise.

The US Energy Information Administration said in January that solar, wind and storage combined are expected to account for 81% of total capacity additions in 2021.

The remaining breakdown, after storage, is 39% solar, 31% wind, 16% natural gas and 3% nuclear. Unit 3 of the Vogtle nuclear power plant in Georgia will come on line this year.

Total capacity additions are expected to hit 39,700 megawatts before any additional boost provided by Biden administration policy changes.

That compares to a forecast of 42,000 megawatts in 2020 — which was expected to be a big year because of a deadline (later extended) to complete wind projects to qualify for full tax credits — and 23,700 megawatts in 2019.

Many of the projects that will be completed in 2021 have already been financed.

The expected geographic distribution is interesting, but not surprising.

More than half of the new solar capacity is going into just four states: Texas (28%), Nevada, California and North Carolina.

More than half the new wind capacity is going into just two states: Texas and Oklahoma.

The second US offshore wind project is expected to reach commercial operation later this year — the 12-megawatt pilot-scale CVOW — coastal Virginia offshore wind — project off Virginia Beach. That will make seven offshore wind turbines in total in operation off the US coast. The first large-scale offshore wind project — the 800-megawatt Vineyard project off Massachusetts — is expected to be in the market for financing later this year.

The largest solar-powered battery is expected to go into service in late 2021: the 409-megawatt Manatee solar energy center in Florida. / continued page 21

PPAs

continued from page 19

if there is no tax equity takeout. The project can still operate and earn revenue, but without the hedge to provide a floor under the potential revenue.

Third, a force majeure event at the project does not equate to a force majeure under the hedge. Hedges typically use the ISDA definition of force majeure, meaning an event is only a force majeure event if it physically prevents a party from making a payment. An example is where a cyberattack occurs and the parties are unable to wire funds as a result. If a hurricane or other force majeure event occurs at the project, typically the hedge will continue to settle. Developers should consider purchasing business interruption insurance to ensure that funds will be available to settle the hedge in such cases.

Electricity basis risk is always borne by the developer in proxy generation PPAs. Basis risk is the difference between the price of power at the hub, where the hedge settles, and the price of power at the grid node, where the project connects to the grid and sells power.

The developer receives the nodal price for the physical electricity delivered to the grid, but the "floating price" the developer must pay under the hedge is calculated using the hub price in lieu of the nodal price. The developer bears the risk that the nodal price is lower than the hub price. If the nodal price is higher than the hub price, the developer reaps that benefit.

Developers should be prepared to post credit support to the hedge provider.

Credit support can take the form of a letter of credit, cash or a creditworthy parent guaranty. Some offtakers might be willing to take a lien on the project as credit support. ◎

Negotiating Hydrogen Contracts

by Rachel Crouch, in Washington

Market standards for hydrogen revenue contracts remain malleable. The hydrogen market is set to undergo rapid change and expansion.

Long-term revenue contracts will be key for early low-carbon hydrogen projects to obtain financing, and developers and their potential customers are beginning to consider appropriate terms for offtake contracts.

This article explores key issues to be evaluated when negotiating such agreements.

Tolling v. Sale and Purchase

It is instructive to compare the nascent hydrogen offtake market to the LNG market. LNG projects have developed two principal models of revenue contracts: tolling agreements and sale-and-purchase agreements.

Under the LNG tolling model, an LNG facility provides natural gas liquefaction capacity to its customers. Each customer is responsible for sourcing natural gas, delivering it to the liquefaction facility, and shipping and marketing the LNG produced with that natural gas. The customer pays the liquefaction facility to convert gas belonging to the customer into LNG.

Similar to LNG, under a tolling model for blue hydrogen projects (where hydrogen is produced by reforming fossil fuels and then capturing carbon emitted from that process), the customer would buy the fuel and pay the hydrogen plant to convert it into hydrogen. Under a tolling model for green hydrogen (where hydrogen is produced from electricity and water through electrolysis), the customer would purchase electricity to be used at the electrolysis plant and potentially also supply the water to be used. It would supply these raw materials and pay the owner of the electrolyzer to convert the water into hydrogen and oxygen.

Under the LNG sale-and-purchase model, an LNG project either produces or purchases the upstream gas and is then responsible for transportation to the liquefaction facility, liquefying the gas and then selling it as LNG.

Similarly, a blue hydrogen developer would procure natural gas and then produce and sell hydrogen made from the gas.

Under a green hydrogen sale-and-purchase arrangement, a project developer would buy electricity and water. As with natural gas, the electrolyzer facility owner may procure electricity in several ways. It may buy electricity from a third party at arm's length by entering into a corporate PPA with a renewable power project. Many corporate PPAs are "virtual" PPAs that act as price hedges. The actual electricity used is purchased in the spot market, but the virtual PPA is a means of fixing the price. Alternatively, the electrolyzer owner may play a role in the power production — because the same project company owns both the power plant and the electrolyzer, because the two plants belong to affiliates owned by a common sponsor, or because the power producer and the hydrogen producer have entered into a joint venture.

There are several factors to consider when determining whether a tolling or sale-and-purchase approach is preferable. First, the availability and terms of a PPA or other feedstock supply agreement will be better for the entity with a higher credit rating — whether that is the hydrogen customer or the hydrogen project company (or, in either case, a sponsor guarantor). Second, different counterparties will be differently disposed to enter into a separate PPA or other energy supply arrangement or to procure the water necessary for a green hydrogen project.

Contracts to supply green hydrogen are a work in progress.

For example, customers that intend to use hydrogen for long-duration energy storage as a complement to electricity generation may be more inclined to choose a tolling model, since such customers have experience, resources or portfolio benefits that may make them better suited than an electrolysis project developer to enter into a PPA or other arrangement for electricity to supply to an electrolysis project.

Users of hydrogen for other purposes may be less motivated to do so. Moreover, independent renewable power producers viewing hydrogen as an extension of their business models may decide to develop a renewable power / continued page 22

IN OTHER NEWS

CALIFORNIA wind and solar projects were ordered to cut back electricity deliveries by a little under 4% in 2020, or 1.6 million megawatt hours.

Such curtailments are expected to increase over time, potentially complicating financings of future projects.

Curtailments increased 66% compared to 2019 and 246% compared to 2018. Most curtailments are at mid-day during periods of peak solar output. They reached 7% in April 2020 when stay-at-home orders were in effect and many businesses were shut down.

The California grid operator expects renewable energy generators to face curtailments of 7% to 17% by 2030 based on the current resource mix projected by the California Public Utilities Commission. Installation of large batteries that shift electricity deliveries to other times of day and mass electrification of the transportation sector could help. Less predictable revenues become a factor in how much financing can be raised on projects.

FEWER CORPORATE PPAS were signed in the United States in 2020 compared to 2019 after three straight years of increases, as COVID and other factors took a toll.

US corporations signed 11,900 megawatts in new power purchase agreements in 2020 compared to 14,000 megawatts in 2019, according Bloomberg New Energy Finance.

Most corporate PPAs are "virtual" PPAs that operate as hedges to lock in a fixed electricity price over a long period, typically for 10 years. The corporate buyer pays a fixed price in exchange for floating payments tied to current spot prices. The corporation uses the floating payments to buy electricity from the local utility. Meanwhile, the renewable energy developer entering into the PPA for a new wind or solar project sells the physical electricity into the local market. (For more details, see "Corporate VPPAs: Risks and Sensitivities" in the June 2020 *NewsWire*.)

/ continued page 23

Hydrogen Contracts

continued from page 21

plant as part of a combined project with an electrolyzer.

In certain jurisdictions, particularly in western states, issues surrounding the party best suited to hold water rights will also need to be considered.

Contract Quantities

Hydrogen offtake contracts are likely to follow a take-or-pay or take-and-pay model so that there is a reasonably predictable revenue stream.

Under a take-or-pay agreement, the buyer and seller agree up-front on a specified contract quantity to be delivered on a periodic basis, and the buyer must either take delivery of that quantity (and pay for it) or pay the seller for any amount not taken, unless the failure is excused under the contract. If a buyer fails to take — but pays for — the full contract quantity, it may be entitled to a make-up quantity at a future date. Take-or-pay contracts are common in the LNG sector.

Under a take-and-pay contract, the buyer must take the agreed contract quantity and pay for it. Failure to take delivery will entitle the seller to remedies for the breach. Damages for failure to take may be contractually stipulated liquidated damages or general damages. Unless the contract provides for liquidated damages, seeking recovery for the breach may take considerable time and expense and will likely require the seller to demonstrate its efforts to mitigate losses as well as proof of actual loss.

Other alternative models for determining the quantity to be delivered exist for hydrogen contracts today that may not be bankable for green or blue hydrogen projects under development. For example, requirements contracts, under which the buyer and seller contract for the seller to fulfill the entire demand of a hydrogen-using project owned by the buyer, or contracts allowing the buyer to nominate different quantities of hydrogen from time to time and requiring the supplier to scale up or down in response, may be too open-ended to be palatable to project finance lenders.

To be bankable, hydrogen offtake contracts — especially for early hydrogen projects — will probably need to be either take-or-pay or take-and-pay (preferably with liquidated damages), for three principal reasons.

First, financiers will require a predictable revenue stream. Second, because there is no merchant market for hydrogen, selling hydrogen not taken and paid for by a customer will not be a straightforward proposition. Finally, in many cases, early green hydrogen projects may not be able to decrease the electricity they purchase under their PPAs without paying for it, resulting in relatively constant input costs and making it critical to have a reliable purchaser for the output.

Pricing

There are currently no spot prices for hydrogen. Contracts for the sale of hydrogen produced from fossil fuels (which constitutes the vast majority of hydrogen sold today) are often based on the actual price of feedstock (usually natural gas), plus other fixed and variable costs and a profit element.

Until a benchmark price for hydrogen is adopted in the market, green and blue hydrogen contract prices may follow a similar formula based on fixed costs plus variable costs actually paid.

S&P Global Platts has launched regional hydrogen benchmark price assessments for different production pathways, including steam methane reformation, steam methane reformation with carbon capture and storage, proton exchange membrane electrolysis (called PEM electrolysis) and alkaline electrolysis. The Platts assessments are based on regional natural gas and electricity assessments, along with assumptions regarding capital and operating expenses. Platts has taken similar cost-based approaches in developing assessments for other non-liquid markets in the past. Offtake contracts for both green and fossil fuel-based hydrogen may look to the applicable regional Platts assessment in determining contract prices.

Given the projected rapid pace of development of the hydrogen market, parties may consider whether to include price review provisions in their offtake contracts. Under these provisions, the parties would review the price formula on an agreed periodic basis or upon the occurrence of certain triggers indicating a change of circumstances. These provisions should be considered carefully because price reviews are very susceptible to dispute, and there are unlikely to be objectively determinable spot prices to rely on by the time the opportunity for a price review arises under early green or blue hydrogen sale contracts.

Given the lack of a spot market for hydrogen and the challenge of transporting it over long distances, negotiating liquidated damages presents a challenge where substitute hydrogen — even traditional "grey" hydrogen produced from natural gas without carbon capture — is not readily available. In such instances, "deliver-or-pay" provisions for the failure of the seller to deliver the contract quantity of hydrogen that look to the cost of procuring alternative hydrogen may be deemed overly punitive.

Offtaker Credit

Project owners and project finance lenders will naturally prefer long-term revenue contracts with customers with strong credit to support their commitments. (See "Emerging Opportunities in the Hydrogen Market" in the December 2020 *NewsWire*.) For many nascent hydrogen use cases, however, the customer may be a start-up company or even a special-purpose project company itself.

In these cases, traditional credit support in the form of a parent guarantee (if a creditworthy parent exists) or a letter of credit may be necessary to make the project bankable.

Project owners should also assess their project's stakeholders to determine where a creditworthy entity may be able to backstop a take-or-pay or similar obligation.

Even if the direct offtaker is not a creditworthy entity, it may have creditworthy customers as its clients — for example, where a start-up refueling company offtaker purchases hydrogen from a hydrogen project with the intention of reselling it to publicly owned bus operators. In this case, the stakeholders may contract for a look-through from the hydrogen project to the governmental entity, where the hydrogen project company may step into some or all of the refueling company's rights to collect from the more creditworthy entity.

Conversely, for use cases where the end user is not creditworthy and cannot support a bankable hydrogen project, there may be a role to play for an intermediary trading company that is creditworthy or able to draw on adequate credit support.

Governments, multilateral institutions or export credit agencies aiming to get the clean hydrogen industry off the ground may also step in to provide guarantees or other credit support when there is not a bankable offtaker or end user.

When considering the size of a planned hydrogen project, developers may need to weigh the savings in capital expenditure per ton that will result from a larger scale against their ability to find a long-term revenue contract with a creditworthy offtaker for the entire projected output at the outset of development. In some situations, particularly where the project will be located close to multiple potential offtakers, the benefits of scale may be such that developers opt to develop hydrogen projects that are oversized compared to their initial offtake contracts.

Cascading Risks

When drafting hydrogen offtake contracts, parties should consider the appropriate allocation of the risk of disruptions to a project's ability to obtain feedstock — */ continued page 24*

IN OTHER NEWS

IHS Markit, a consultancy, predicts that between 44,000 and 72,000 megawatts of new corporate PPAs will be signed in the United States through the rest of the decade. Bloomberg New Energy Finance says the 285 corporations that belong to the RE100 will collectively have to sign PPAs through 2030 that could lead to as much as 93,000 megawatts of incremental new wind and solar projects.

AS FRUSTRATING AS TRYING TO GET A COVID VACCINE. Callers to the Internal Revenue Service with tax questions have roughly only a one in 11 chance of getting through currently, according to the IRS.

— contributed by Keith Martin in Washington

Hydrogen Contracts

continued from page 23

be it natural gas, electricity or water.

Parties will need to address the effect of potential delays in completion of any project that will supply an input for producing hydrogen. Offtake contracts can be expected to specify a deadline for the first delivery of hydrogen. Delays may result in liquidated damages or termination rights. If a green hydrogen project is being developed alongside a new renewable energy power plant, the timing risk for the project is multiplied. In some cases, green hydrogen projects may also need to be undertaken together with water treatment or desalination projects, adding further timing risk.

Parties will also need to address the risk of an interruption of feedstock supply. LNG sale-and-purchase agreements again provide useful precedents for how this may be managed in hydrogen offtake agreements.

A series of threshold questions must be answered during drafting.

In LNG sale-and-purchase agreements, the non-availability of economically obtainable feedstock or the interruption of feedstock transportation is often explicitly excluded from the definition of force majeure. However, in many cases, force majeure under a gas supply or transport agreement will be force majeure under the corresponding LNG sale-and-purchase agreement if it results from an event that would also satisfy the definition of force majeure under that LNG sale-and-purchase agreement. Similar provisions could be adopted with respect to electricity or natural gas for hydrogen revenue contracts.

Developers and their financiers should make an effort to ensure that the force majeure provisions in hydrogen project PPAs or other supply agreements and their offtake agreements are back-to-back to the extent possible, both when it comes to extensions of commercial operation deadlines and to interruption of supply.

Other Risks

Although government support frameworks are still developing for green and blue hydrogen, most if not all early projects will benefit from a subsidy or tax incentive that will underpin the economics of the revenue contracts. The cost of complying with an offtake contract will also be affected by law, regulation and government policy — for example, with respect to safety, gas specifications and export or import restrictions. Hydrogen offtake contracts will need to specify clearly which counterparty bears which change-in-law risks.

Today, hydrogen projects are often located at or near their offtakers' plants — usually petroleum refineries or ammonia production facilities. Most early green and blue hydrogen projects will probably follow this model, although market participants are looking ahead to the transportation of hydrogen through pipelines (either blended with natural gas or on its own), on trucks or on ships. Any time a hydrogen project is not co-located with the offtaker, the offtake contracts will need to specify clearly the point of transfer of title and risk of loss. Hydrogen project developers and their customers should consider which counterparty is the best positioned to store, transport and deliver the hydrogen and to bear risks associated with those activities.

Green or Blue Certification

It will take time for green and blue hydrogen to become cost-competitive with hydrogen produced via reformation of fossil fuels without carbon capture. Companies buying hydrogen with the objective of decarbonizing their energy use or governments supporting the development of a low-carbon hydrogen economy should, for at least the next decade, expect to pay a premium for low-carbon hydrogen purchases.

To allow for price differentiation, it will be necessary that green or blue hydrogen be certified as such or otherwise be demonstrably derived from renewable energy or complemented with carbon capture.

Representations and warranties as to the electricity or carbon capture associated with hydrogen production may be included in hydrogen offtake agreements.

Perhaps more importantly, third-party certifications may be required. An early example of this is the European CertiHy scheme, which provides green and low-carbon guarantees of origin.

In the case of blue hydrogen, in the absence of government-imposed standards, counterparties may look to standards developed in recently signed LNG sale-and purchase agreements that incorporate statements of greenhouse gas emissions. Credit given for carbon captured will need to account for carbon re-released through use or leakage. This issue is under scrutiny by developers looking to take advantage of the section 45Q federal tax credit.

California has developed a low-carbon fuel standard (LCFS) under which suppliers of low-carbon fuels earn credits. The value of the credits is negatively correlated to the carbon intensity of the fuel. (See "Financing California hydrogen projects using LCFS credits" in the December 2020 *NewsWire*.) These credits may do away with the need for other forms of carbon verification in the market for hydrogen as transport fuel in California and could provide a model or reference point for certifications or representations in bespoke transactions in other markets.

National standards for differentiating low-carbon hydrogen from traditional carbon-intensive hydrogen will need to be developed by governments or third parties. International coordination will be necessary to develop rules and standards as export markets develop. ◎

Expected Changes in Renewable Energy Policies

Investors watch for potential inflection points in markets. Many people will be focused this year on what changes the new Biden administration will make to accelerate deployment of renewable energy and to address climate change. Three knowledgeable Washington observers talked about what to expect at the annual renewable energy law conference hosted by the University of Texas in Austin in late January. The following is an edited transcript.

The panelists are Abigail Ross Hopper, CEO of the Solar Energy Industries Association, Heather Zichal, former second-term Obama energy czar and the new CEO of the American Clean Power Association, which is the successor to the American Wind Energy Association, and Richard Glick, incoming chairman of the Federal Energy Regulatory Commission. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Infrastructure Bill

MR. MARTIN: Abby Hopper, what do you expect to see for renewable energy in the clean energy and infrastructure plan that Biden will propose, and when do you expect the details to be released?

MS. HOPPER: Let me say first that I am thrilled to have an administration that prioritizes the intersecting crises that our nation is facing — the climate crisis, the environmental crisis, the environmental justice crisis, the economic crisis — and that sees clean energy as a path to tackle all of them at one time.

What I think will happen is that all the levers of government will be used to solve those crises.

We should see an infrastructure package fairly soon. There will be things for clean energy — like transmission, like tax policy, like funding for research and development — but the focus will be on acceleration.

The clean energy transition is happening. The market has spoken. There is no question about the direction in which things are headed. How quickly it will happen is what is up for grabs. I think this administration will focus on rapid, rapid deployment, and that is what I am excited about.

/ continued page 26

Policy Changes

continued from page 25

MR. MARTIN: Heather Zichal, do you have any sense of what might be in it and when it will be announced?

MS. ZICHAL: The early indications are we may start seeing details as soon as February.

In terms of the substance itself, to Abby's point, the new president has made it clear that climate policy is at the front and center of how he is thinking about economic policy. The Biden team is taking a holistic approach and thinking about not only what the Treasury department and US Trade Representative can bring to the table on climate policy, but also what other parts of government can do as well.

They are looking at things like what differences we can make in the power sector, how we can rapidly deploy zero-emission vehicles, and how to rebuild our crumbling infrastructure in a way that can withstand a changing climate. I am very hopeful that we will have a robust package that will drive not only meaningful change on the climate agenda, but also create millions of high-paying quality jobs.

A tax credit for standalone storage has a good chance being enacted this year.

MR. MARTIN: The US Chamber of Congress and the Bipartisan Policy Center said they hope the clean energy and infrastructure bill can be enacted by July 4. Is that realistic?

MS. ZICHAL: If I had a crystal ball and could tell you dates and times, I would be the most popular woman in Washington. Unfortunately I don't, but the infrastructure agenda should be something that can unite Republicans and Democrats.

Everyone is for job creation. Our Clean Power Association member companies are creating jobs in all 50 states. There is a growing interest in addressing climate policy on both sides of the aisle. I think Biden is uniquely situated to deliver a policy in a way that can garner bipartisan support.

In terms of timetable, July is fairly optimistic to be through the entire legislative process, but we are going to do everything we can to create political space and ensure success for that package.

MR. MARTIN: Abby Hopper, do you think the clean energy and infrastructure bill will have to pass as a budget reconciliation measure so that it requires only a majority vote rather than the usual 60 votes in the 100-member Senate and, if so, what are the implications for what can be included?

MS. HOPPER: I think what you are asking about is the durability of a climate policy. That is important. We learned that in past legislative battles.

I echo what Heather said. The notion that a clean energy transition is partisan is a false narrative. All of our polling shows that Republicans and Democrats both believe the government should play a stronger role in helping with the transition. Look at places like South Carolina. A couple years ago, it had a Republican governor and a Republican legislature, and it passed a really good bill to encourage wider adoption of solar within the state.

That gives me some hope that the clean energy pieces of a larger bill will remain durable going forward.

MR. MARTIN: Heather, polls have shown that the Republican party, as a whole, does not really believe that government action is required on climate change. The Republicans in Congress have been pretty unified in their opposition. Do you see a major break in this now that Trump has left office?

MS. ZICHAL: I am very optimistic that we will see a break. It is not just because this reflects a growing desire among the American electorate. When the Biden administration announced we are rejoining the Paris climate accord, every major corporation and trade association, including the American Petroleum Institute, embraced that move.

There is a little bit of a misconception about what is possible in this area. Biden will hit the reset button, and then we will find out. The American Clean Power Association members are putting steel in the ground. We are creating jobs. I think that is an agenda that both Democrats and Republicans can get behind.

Odds

MR. MARTIN: Let me drill down into some details and ask what odds you place on any of the following being enacted. Starting with Abby Hopper, how likely do you think it is Congress will enact a tax credit for standalone storage this year?

MS. HOPPER: Likely. That is one of those things for which there is broad bipartisan support.

MR. MARTIN: Heather Zichal, same answer?

MS. ZICHAL: Yes. Absolutely.

MR. MARTIN: What about a direct-pay alternative to tax credits. Abby, what are the trade associations asking for at this point? The House passed a quick-refund program last July that would work through the IRS rather than the Treasury and refund only 85% of the credit value.

MS. HOPPER: We have seen a tightening of the tax equity market. We are asking for refundability in a quick and effective way to get the market moving. I don't think 85% is enough. We are lobbying for a bit more than that.

MR. MARTIN: Is the plan still to rely on the IRS rather than the Treasury?

MS. HOPPER: I don't think we have a particular preference for one over the other.

MR. MARTIN: What are you hearing from Democrats who traditionally have not been keen to make direct payments to companies?

MS. HOPPER: I think there is a recognition that these are unprecedented times. The economic situation remains challenging. A short-term, direct-pay option is different than a long-term payout to corporations, so I think there is some appetite to do that.

MR. MARTIN: Heather Zichal, what are you hearing about this?

MS. ZICHAL: The ACP is new and so I have been spending a lot of time talking to members. Direct pay has been a priority for every single CEO to whom I have spoken. We are going to be aggressively supporting and lobbying for 100% direct pay.

Direct pay is fair game in a reconciliation package. We are seeing growing receptivity to it. There is a growing recognition that we need to pull out all the tools that can help to deploy clean energy and create jobs as quickly as possible.

MR. MARTIN: Have you just given us a signal how you want your new trade association to be referred to — A-C-P and not sound out all the letters like for the other trade associations, SEIA or AWEA? Not ACK-pa?

MS. ZICHAL: Please don't call me ACK-pa! That would make me very sad.

MR. MARTIN: Obama tried to get a clean energy standard through Congress, and it failed in the House after the politics changed in 2010. Do you think that will be on the Biden agenda as part of the infrastructure bill?

MS. ZICHAL: Unclear. I do think that there is broad recognition because Biden has such a large climate team that is well versed in the policy . . . . Sorry about my dog. He gets jealous when I have cameos.

MR. MARTIN: He is more than welcome.

MS. ZICHAL: I think there is broad recognition across the administration about the need for a long-term price on carbon. Whether that is a carbon tax, whether it is a clean energy standard, I think they are going to want to keep an open mind and hear from Capitol Hill, industry and other key stakeholders about what the best way is to address this.

The good news is that there are tools readily available that will lead to more deployment of clean energy. We all know what the science says. We all know that we lost the last four years and this is really our moment to take the reins and rapidly deploy these projects. We have a great opportunity to hit the ground running with this new administration.

MR. MARTIN: Dogs are supposed to be good judges of character. Maybe after the last four years, a litmus test for people in important positions should be whether dogs like them?

More Extenders?

MR. MARTIN: Abby Hopper, this is the $64,000 question. Are you pushing for a further extension of the renewable energy tax credits and, if so, at what level and for how long?

MS. HOPPER: The companies that belong to Heather's and my trade associations want certainty. They want to know how can they plan for their businesses. Government actions that upend their economics are not welcome developments.

Yes, we are advocating for a stable policy that allows businesses to grow. My job is to do that. That's what SEIA does. We lobby for a competitive environment in which solar and storage companies can continue to grow. That means a clean / continued page 28

Policy Changes

continued from page 27

energy standard. That means extensions for tax credits.

We are a bit agnostic about what the correct policy tool is. We are very focused on the outcome. The art of the possible will influence what we lobby for, but the desired outcome is clear. It is a stable business environment so that capital can be deployed and projects can be built.

MR. MARTIN: Heather, many people are asking whether the tax credits will be extended again and increased in amount. They were just extended on December 22. What do you think?

MS. ZICHAL: We are in the early days of the new Congress. People are still trying to determine the priorities and what should loom large on the climate agenda.

We have a new chairman of the Senate Finance Committee who has introduced a bill that is really interesting and has some potential momentum. He is proposing a technology-neutral tax credit whose amount for any particular taxpayer would be based on emissions. If you want to think strategically about cleaning up the tax code, about doing something that creates a level playing field for wind, solar, storage and offshore wind, I think that approach has potential benefits.

Tariffs

MR. MARTIN: Abby, what do you expect to happen with tariffs on solar panels?

MS. HOPPER: In October, the former president issued a proclamation that revoked the bi-facial exemption and then slowed the stepdown in tariff amounts for all solar panels. We have been litigating his prior attempts to remove the bi-facial exemption. We continue to litigate that.

Business does not do well with unpredictable rules. Deals that were in process prior to a proclamation last October were affected by the change in step-down rate.

We are asking for the original phase-down schedule to be restored. We think the bi-facial panel exemption should be put back in place. There is no reason to collect tariffs on a product that is not being manufactured in the United States.

Beyond that, these tariffs do not need to be extended. There is zero policy reason to do that. There is certainly a policy discussion to be had about how we can incentivize domestic manufacturing. SEIA has done a lot of thinking about this. We put out a white paper about what those policies should be and have been talking to the new administration about that.

MR. MARTIN: SEIA moved quickly to encourage solar companies to diversify their supply chains after the news broke about forced labor practices in Xinjiang province in western China. Do you expect Congress to pass a bill banning imported products from the region? Do you expect the administration to take action on its own without waiting for Congress?

MS. HOPPER: We expect that to happen in some form, and that is why we have been so out front on this issue. We are working quickly to develop a traceability protocol so that not only do we have companies assuring us that they are not sourcing from there, but we also have objective ways to confirm that the supply chain is free from forced labor.

Other Biden Actions

MR. MARTIN: Heather, Biden has already issued a series of executive orders that will help renewables.

He gave notice that the United States will rejoin the Paris climate accord. He is ordering federal agencies to buy more renewable energy. The next item hasn't happened yet, but the SEC and bank regulatory agencies are expected to require more robust disclosures about climate change effects. Biden has instructed federal agencies to take account of the full social cost of greenhouse gas in their rulemaking. BOEM is expected to start issuing construction permits for offshore wind.

Are there other things you expect that are not on this list?

MS. ZICHAL: There are a few things. The administration not only is taking proactive measures through the executive orders, but is also identifying any problematic decisions that were made by the Trump administration that need to be revisited. A handful of issues are likely to bubble up to the top from that process.

I expect the administration to set a national target to achieve 100% clean energy in the electric sector by 2035 together with some accompanying steps.

I would not be surprised to see targets for permanent renewables on federal lands and waters, including offshore targets. Another likely effort is getting the Department of Transportation and the Environmental Protection Agency to work together on revised fuel economy standards.

I am sure Chairman Glick will speak to some of the other steps the Federal Energy Regulatory Commission is likely to take. There is a basket of issues around permanent challenges and environmental review that I expect to see from this administration.

MR. MARTIN: Does either of you expect a carbon tax to be enacted or a carbon border adjustment to be imposed?

MS. HOPPER: I don't think we are at the point of enacting a carbon tax, but the technology-neutral tax credit proposal from Ron Wyden, the incoming chairman of the Senate tax-writing committee, is a step on the journey toward addressing carbon emissions.

MR. MARTIN: Heather, do you expect a carbon border adjustment?

MS. ZICHAL: I think this administration will keep all options on the table. There is a lot that is not known about the appetite in Congress. At the end of the day, any administration sets priorities. There are things on which it will choose to spend political capital, and there are things that are too controversial to pass.

The lens through which the administration will view all of the possible policy tools is which will drive the most renewable or clean energy deployment across all sectors? Which will create the most economic opportunity?

Transmission

MR. MARTIN: Let's move next to someone whom dogs like, the new chairman of the Federal Energy Regulatory Commission, Richard Glick. He is well liked in Washington. He is a veteran of the renewables policy debates, as he has spent his entire career on them.

Wind developers have been saying for some time their number one issue is lack of transmission. FERC has had backstop authority to force siting of interstate transmission lines within national-interest corridors since 2005. A US appeals court in 2009 set aside a FERC order laying out procedures to invoke the authority.

Why hasn't anything been done by FERC since 2009 to fix the procedural problems? Is this an area where action is expected this year?

MR. GLICK: First, I have to warn you that I have a couple cats, and they may walk in like Heather's dog did.

FERC does have backstop siting authority for transmission, but the 4th circuit court of appeals ruled several years ago that the authority is somewhat limited. You are correct that the transmission would have to be located in an interstate national-interest corridor. The court ruled we can only act when a state fails to act on a transmission siting request. If a state acts by saying 'no,' per the court ruling, we can't do anything about it.

Some members in Congress have introduced legislation over the years that would overturn that decision and give us backstop siting authority in cases where a state says "no." Some commentators have suggested that we do not need to wait for Congress and should act in cases where a state rejects a transmission siting request, but I think it is better to give Congress time at least to decide whether to overturn the decision.

Siting has been a very important issue. It has been very difficult to site some long-distance transmission lines that would provide access for remotely located renewable resources. Any such lines have to cross a number of states, and one state can veto the entire project.

But there are a lot of other issues. I think FERC can play a role in getting transmission lines built. Planning, cost allocation and incentivizing transmission are three areas where we are going to be spending a lot of time in the near future.

MR. MARTIN: Do you think Congress is likely to weigh in on this given the tension between states' rights and federalism?

MR. GLICK: It is a difficult issue because it involves eminent domain. We see that flaring up with natural gas pipelines, as well. FERC has federal authority over siting of natural gas pipelines. That has led to lots of litigation and angst from both sides of the political spectrum. That is another reason why these are such hard questions for Congress to tackle. As for the 4th circuit decision, our best approach is to ask Congress for more clarity around what it intended when it gave us the backstop siting authority.

MR. MARTIN: You mentioned cost allocation. As you know, renewable energy developers often compare the grid to an interstate highway that makes the last car entering the interstate pay the full cost of any needed upgrades. The utilities complain at the same time about bloated interconnection queues and the amount of time they must spend studying the effects not only on their systems, but also on other affected systems nearby.

What role does FERC have in fixing this, and how do you see FERC fixing it?

MR. GLICK: We have a significant role to play in a couple respects. First, in terms of allocating the cost of transmission upgrades, the courts have essentially told us that we have to allocate the costs in the same manner as the benefits are received. What happens currently is the developer whose project triggers the need for the transmission upgrade is usually assigned most, if not all, of the cost, which can be pretty significant.

We have to recognize that there will be other beneficiaries. When transmission grids are upgraded, that gives utilities greater access to lower-cost generation. We need to take a look at our cost allocation priorities.

In addition to that, it seems to me that if one project gets built and the developer has to pay for the entire cost of a network upgrade, others who follow may also benefit. They get a free ride. That is another issue that we will need to address.

Finally, I think we need to figure out a / continued page 30

Policy Changes

continued from page 29

way to improve the interconnection process. In many of the regions we are talking about, something like 90% of the projects sitting in queues are wind and solar. It takes a long time to get to the front of the line. FERC has authority to deal with some aspects of this. I would like for us to look at it further because it is an important barrier to the transition to renewables.

MOPR

MR. MARTIN: Good list. It will take a little time to work out solutions to those issues with your colleagues on the commission.

Let's move to the MOPR. You have been a critic of the minimum offer price rule that forces renewable energy generators bidding into capacity auctions in PJM to bid at least a minimum price. The counterpart in New York is called the BSM rule. It requires bidders in the New York City and Hudson Valley capacity markets to meet a price floor until their capacity has cleared 12 monthly auctions.

How and when does this get resolved?

MR. GLICK: At our last monthly meeting just before Trump left office, there was a proposal to take up a petition to expand the New York program to the entire state. That proposal was rejected by a vote of four to one. That means the petition is still pending, so I am not permitted to talk about how we might act on it.

I will say in general that I have been critical of MOPR programs and of the New York program in particular. BSM stands for buyer-side market power. We are imposing these requirements on renewable energy generators, storage projects and others that are not buyers and have no market power. That doesn't make any sense to me. I would like the commission to address the issues involved and provide more clarity.

MR. MARTIN: There are two capacity auctions scheduled this year for PJM. One is coming up pretty quickly, and I believe the MOPR will apply to it. Another one is expected in December. Will the MOPR apply to the one in December?

MR. GLICK: I believe the first one is in May. It is hard to make a prediction about the rules that will apply to any future auction. I have four other colleagues on the commission, and we have to get three votes for a particular position to move forward.

That said, I think everyone recognizes that the days of the MOPR are numbered. State regulators, RTOs and stakeholders around the region don't like it. It has been a complete mess since the commission started down this path a few years ago. We created a lot of uncertainty. People don't know, even for the auction coming up in May, what the rules are. We still haven't established all the rules yet.

I think we need to reconsider how we address capacity markets and all the other markets in RTOs around the country. We need to figure out a better way forward to accommodate state clean energy programs and not try to block them through pricing mechanisms.

MR. MARTIN: The MOPR is tied up in two US appeals courts. Do you expect FERC to ask the courts to send it back to FERC for reconsideration?

MR. GLICK: It is something we need to discuss internally. I have only been chairman for a few days and have not had a chance to talk yet to the commission staff about this.

Storage

MR. MARTIN: Switching topics, FERC has been wrestling with whether to treat storage as generation, transmission or a hybrid of the two. It held a technical conference last October. Two questions: first, what difference does it make how batteries are treated?

MR. GLICK: There is some benefit for storage providers to be treated as transmission. If a battery is a transmission asset, then you get to recover your cost plus a reasonable rate of return on your investment from all users of the grid. If the battery is a generation asset, the return is subject to the whims of the market.

Most of these markets are competitive. Obviously when prices are high, you do well, but when prices are low, you don't do as well. It is probably a little more difficult to obtain financing for a storage project that is treated as a generation asset.

Over the last several years, we have had individual storage projects ask to be treated as transmission assets. We have addressed those requests on an individual basis. Recently, Mica came in with a more generic proposal about when storage projects should be treated as transmission. We issued an order allowing Mica to do that under some very narrow circumstances.

We still need as a commission to provide clearer guidelines for when we will allow storage to be treated as transmission. There is a string of issues. For instance, should storage projects that are treated as transmission assets be allowed to participate in the energy market when they are not being used for transmission? What should happen in a transmission planning process when you have multiple storage assets and only some of them are treated as transmission? There is a potential for discrimination.

MR. MARTIN: My next question was going to be when will this be sorted out? It is clear there are still a lot of issues in play.

MR. GLICK: I think so. We are working our way through them. It is better like we did with Mica to try to address these issues on a more generic basis.

Trump Grid Order

MR. MARTIN: A Trump executive order last May barred the purchase or use of equipment from companies in foreign adversary countries that might cause harm to the US electricity grid. An example may be some types of Chinese equipment. FERC issued a notice of inquiry in an attempt to collect information about the extent to which potentially risky equipment is already being used by US power companies. As you can imagine, an order banning something immediately without being clear about what is banned creates challenges when financing transactions.

What do you see as the next step in this saga?

MR. GLICK: One of President Biden's day-one executive orders sensibly froze various Trump administration orders, including this one.

The new administration will make its way forward. I think the issue will be whether to issue a whitelist or blacklist of equipment or entities that are allowed or banned. Any such list would come from the Department of Energy or the Department of Homeland Security.

From FERC's perspective, we have authority, along with the North American Electric Reliability Corporation or NERC, over reliability of the bulk-power system. My colleagues and I at FERC are greatly concerned about security issues. The concerns extend not just to hardware, but also to software. We saw in the recent SolarWinds incident that software can be a significant problem for cybersecurity.

FERC will continue to assess what requirements should be imposed on utilities. Some such requirements are already in place. However, we are not the agency that will make decisions about particular types of equipment. Other agencies are better equipped to handle such questions.

Other FERC Actions

MR. MARTIN: FERC said in a policy statement last fall that it is open to having the RTOs incorporate carbon pricing into their markets. What is an example of what FERC would entertain?

MR. GLICK: We are sifting through the comments about the policy statement now. We have not finalized that policy statement yet.

As for an example, New York has imposed a carbon pricing regime for a number of years. Since we have authority over the wholesale markets, if the New York ISO were to tell us that it wants to apply the same policy to incorporate a price for carbon into wholesale power prices, the policy statement suggests we would approve that.

It is a little more complicated when you have multi-state RTOs, which we do in most parts of the country, but I think we have signaled that the commission is serious about accommodating state carbon policies, even in a multi-state system.

MR. MARTIN: FERC issued an order called Broadview Solar last fall that attracted a lot of criticism. It addresses how to measure project size where, for example, a project has a nameplate capacity of 130 megawatts, but the inverters limits the electricity that can actually be delivered to the grid to 80 megawatts. Is it an 80-megawatt or a 130-megawatt project for purposes of the 80-megawatt limit on when utilities can be required to buy the electricity under PURPA?

FERC basically said it is 130 megawatts, but the commission did not explain how adding a battery affects the capacity. Do you know the answer?

MR. GLICK: I dissented from that particular order and the order is pending on re-hearing at FERC, so I am not allowed to comment specifically.

We are still making our way through what it means to have an 80-megawatt project when the nameplate capacity is more than 80 megawatts, but the project is only able in practice to send 80 megawatts or less to the grid. Hopefully the commission will speak on it soon.

MR. MARTIN: Last question. Environmental justice has become more important. Both you and Allison Clements, the other Democratic commissioner, have been talking about it. FERC expects finally to stand up a new office to give the public more input into policy decisions before the commission. I read somewhere that the new office might charge applicants for FERC orders fees to help interveners to cover legal costs to intervene. How do you expect this to work?

MR. GLICK: Congress actually created an office of public participation in 1978, but for some reason, FERC never established the office. Congress included language in the most recent COVID-relief bill in late December directing the commission to deliver a plan for moving forward with that office. We expect to establish the office soon.

All of our expenses are funded currently via fees on various stakeholders that participate in */ continued page 32*

Policy Changes

continued from page 31

proceedings at the commission. For instance, when you file a complaint, you have to pay a fee. When you ask for a declaratory order, you have to pay a fee.

Most fees are used to fund the commission's activities, and I think people are suggesting that the office of public participation would be funded the same way. We are still working our way through the language in the original bill creating the office and the most recent bill that just passed.

No decision has been made about whether we need to go to Congress to get extra appropriations to fund intervenor participation or we can do that with the existing fees we impose on everybody.

Environmental justice and the office of public participation will play a role in future decisions on such things as the siting of natural gas pipelines and hydroelectric facilities. The commission has not really paid significant attention to environmental justice considerations in the past. It is something that I am committed to do as we move forward.

MR. MARTIN: Those of you watching on Zoom can't tell, but this program has now gone to the *cats and* dogs. Our producer has a cat walking across her desk between her and the camera. Thank you, panelists. ◎

New Trends in 2021

The Infocast Projects & Money conference each January is a good leading indicator of how strong a year it will be in terms of deal flow. If the CEOs are out in force, they have time on their hands, and it will be a slow year. The conference was virtual this year. The opening panel was a wide-ranging discussion via Zoom with four of the industry's big thinkers about new trends in the market.

The panelists are Jonathan Bram, a partner with Global Infrastructure Partners, Ted Brandt, CEO of Marathon Capital, Himanshu Saxena, CEO of Starwood Energy Group, and Sarah Slusser, CEO of Cypress Creek Renewables. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Overall Market

MR. MARTIN: Jon Bram, how would you characterize the current state of the market?

MR. BRAM: The market today is absolutely exciting. It is very attractive in terms of the volume and access to capital at attractive pricing. People have much more ambition to do larger transactions now than they had 18 months ago.

MR. MARTIN: Ted Brandt, same question.

MR. BRANDT: The market going into 2021 is very strong and getting stronger. We are seeing massive amounts of liquidity looking for places to go from all over the world. At Marathon, we focus largely on the clean and sustainable areas of the market, but clearly the traditional, mature parts of that market are seeing condensed yields and more and more risk assumption by buyers. Some newer areas, like renewable natural gas, are growing at impressive rates.

MR. MARTIN: I was going to ask how much of the liquidity is being driven by the US Federal Reserve pumping so much money into the economy, but I think you addressed that when you said the liquidity is coming from all over the world.

MR. BRANDT: The last few auctions we have held produced winners from Canada, Europe and Asia. Normally I get on a panel like this with you Keith, and you always ask me "Have yields changed?" and I usually say, "No, they're about the same." But for the first time ever we are watching yields condense.

MR. MARTIN: Is that true across the sector?

MR. BRANDT: There is much more of this in the markets where you cannot put leverage or where raising tax equity is difficult. In the mature segments of onshore wind and utility-scale and distributed solar, every auction produces a new low yield for the bidder.

MR. MARTIN: What are yields in those areas?

MR. BRANDT: We are seeing leveraged returns of 6.5% to 7%. Those used to be the figures for unleveraged returns. Leveraged returns used to be 2% to 3% higher.

MR. MARTIN: Those are returns for the cash equity that is at the back of the capital stack?

MR. BRANDT: Correct. It is behind debt and tax equity.

MR. MARTIN: This is a good bridge to Himanshu Saxena, who complained during this same panel last year about how long the cash equity investors must wait to get their capital back, let alone a return. Himanshu, how would you characterize the current state of the market?

MR. SAXENA: It is really exciting, in part because we are now truly undergoing the energy transition to the green economy. There has been a massive acceleration in the last few quarters, and COVID seems to have not done anything to slow it down. If anything, the transition is accelerating.

With the two Georgia Senate seats changing hands just a couple of weeks ago, I think 2021 and 2022 will result in a major resetting of how many participants are approaching the market. Utilities are starting to get out of the gas business. There are tons of local gas distribution companies up for sale. Oil and gas companies are getting into renewables on a broader scale than just offshore wind. We are spending as much time talking to oil and gas companies, chemical companies and industrial gas companies as to traditional renewable energy developers. Different industrial segments are coming together, and this is creating new types of investment and collaboration opportunities.

It is time to go up to the 20,000-foot level, take a fresh look at the landscape and rethink where are the best places to put our capital.

MR. MARTIN: Investors like inflection points when everything changes. We will come back to what you are chasing. Sarah Slusser, you bring a pure developer's perspective to this. How would you characterize the market?

MS. SLUSSER: Incredibly exciting, just like everyone said. I really am pinching myself. I can't believe that we are at this point where solar has reached grid parity in multiple states. Distributed solar is as exciting as utility-scale solar in terms of opportunity. We have 1,600 megawatts of operating assets at Cypress Creek, so we are not only a developer but also an operator of power plants. Having operating clean energy assets in a market with all the money that wants to invest into ESG is a tremendous opportunity. We are really excited that the world has come around to loving clean energy.

MR. MARTIN: Let me go off on a tangent for a moment. Himanshu Saxena, Sarah Slusser mentioned ESG investors. One of the things you are targeting is carbon capture. Is that an ESG play?

MR. SAXENA: It is. Carbon capture is an area where investors can have a meaningful impact on the environment. It is very much an ESG play because it is an opportunity for emitters of carbon dioxide — for example, from gas plants or cement plants — to capture and dispose of it and, in the process, reduce their carbon footprints. The federal government offers section 45Q tax credits as an inducement for 12 years. These types of projects are starting to make more sense now than they ever have in the past. Oil and gas companies, in particular, are looking at carbon capture as a way to reduce their carbon footprints. We see this as an area that will be active over the next few years.

COVID Effects

MR. MARTIN: Sarah Slusser, how is COVID affecting the ability of developers like you to get projects built?

MS. SLUSSER: It is remarkable how well companies have made the transition to remote work. We have done zoning meetings remotely. We have gone through lots of virtual approval processes at the county level. People have become incredibly creative. It is harder to negotiate land agreements remotely, because a lot of that is personal. We have had no trouble raising capital without meeting in person. We did two huge financings in 2020 — all remote and with no in-person meetings.

MR. MARTIN: Sarah what about the construction crews out in the field? Has COVID affected the actual construction?

MS. SLUSSER: Our construction workers were all considered essential workers, so no. We have been able to push forward with the proper social distancing, wearing masks and taking other safety measures.

MR. MARTIN: Ted Brandt, how is COVID affecting the ability to get projects financed?

MR. BRANDT: There clearly was a market meltdown in March, and that extended through April. Then the Fed came in with a major accommodation and the PPP loan program was put in place by Congress for small businesses. It was still possible to do club bank deals and close on tax equity. Some tax equity investors were still issuing new commitments. Some remained on the sidelines. It seemed by June or July like things had normalized. Everything that was supposed to close closed, at least for us.

MR. MARTIN: Are any of you getting on planes and traveling to business meetings? */ continued page 34*

New Trends

continued from page 33

MS. SLUSSER: I am not.

MR. SAXENA: Not getting on planes, but doing business meetings.

MR. BRANDT: I am. We have had several clients that said "We are not putting all our eggs in your basket without meeting in person." We try to do it appropriately socially distanced, but I have traveled six times since the summer.

MR. MARTIN: Himanshu, are the business meetings virtual or in person?

MR. SAXENA: We are doing some in-person meetings. We do a lot of work with developers, and there are still people, especially developers whom we have not met before, who want to see you in person to assess whether you are trustworthy. We have done in-person meetings sitting six feet apart in a big conference room.

MR. BRAM: It is hard to buy business on a Zoom call. We have had a few dozen meetings.

MR. MARTIN: Most of last year seemed like a Formula One race where there was an accident on the track and all the cars were told to slow down and remain in position.

Sarah Slusser, you raised $200 million in early November in holdco debt against the portfolio of 1,600 megawatts of operating projects you mentioned. Can you say what the spread was above LIBOR?

MS. SLUSSER: It was 450 basis points above the LIBOR, and we had a LIBOR floor of 1%.

Storage

MR. MARTIN: Let's move to new trends as we enter 2021.

Storage is one big one. It has moved quickly to being financed on a quasi-merchant basis. A financing for a large portfolio of standalone batteries in ERCOT will close this month. The source of debt repayment is revenue from providing ancillary services to the grid. There is a hedge to put a floor under the potential revenue stream.

It took wind projects years before they could be financed on a merchant basis. Solar came next after a lag of another few years. Now, all of a sudden, storage is already there. Are there other senses in which storage has passed a tipping point?

MR. BRAM: I think so. Two years ago, visionaries talked about the need for storage in the abstract, and a few very intrepid developers started to move forward. We have committed to more than 1,000 megawatts of storage investment in just the last 18 to 24 months through our Clearway platform.

We have commercial and industrial customers who require solar plus storage. This has moved quickly from something that people thought of as forward looking to a realization that the growing renewables penetration means storage will be needed everywhere. It is not just in California where storage is already entrenched, but also in ERCOT. This is a whole third lane of meaningful investment for us.

MR. SAXENA: Storage is at a different starting point than wind and solar were.

Many years ago, fully contracted wind and solar projects with 15- to 20-year contracts were available for investment. You had output uncertainty, but you did not have any price uncertainty.

With storage, every deal we have seen has less than 50% contracted revenue. For example, in California, we see 30% to 40% of revenues locked in under a 10-, 15- or 20-year RA — or resource adequacy — contract, but the rest of the revenue is merchant.

In Texas, we are seeing deals with three-, four- and five-year contracts, but less than 50% of the revenue is contracted.

Equity investors have always been comfortable taking that risk. Lenders have figured out that if they want to play in this market, they have no choice but to underwrite some floor value for the uncontracted revenue.

It is not clear how the market would react if somebody came to market with a $600 to $700 million financing of storage assets that has that risk component to it. Is that something that would clear the market? I don't know because it has not been tried yet, but $100 to $200 million financings with a club of three or four banks can be done where there is a 50-50 split of contracted versus uncontracted revenue.

MR. MARTIN: Sarah Slusser, what percentage of your utility-scale solar projects now have storage?

MS. SLUSSER: Almost every interconnection application we are making today will have a storage component to it.

MR. MARTIN: Does it make sense to retrofit existing projects?

MS. SLUSSER: Yes. We are looking at whether there is some advantage to that under our existing power purchase agreements. That is an avenue for improvement of our existing fleet. One reason why it is good to be a developer who owns operating assets is you can improve on the portfolio as new technologies like storage come into commercial realization.

MR. MARTIN: AES sold down a 12% interest in Fluence, the storage company that it owns in a joint venture with Siemens, for $125 million to the Qatar Investment Authority at a price that was 1.5 times gross revenue. What does the price suggest about how the market views the prospects for standalone storage?

MR. BRANDT: There is no question that standalone storage is getting financed, but in most cases with all equity. People are bullish, as Jon Bram said, about the general market, and there is demand. The issue is really the revenue model.

The RFP process pushes more and more risk on bidders. All of the engineers predict that the ancillary services revenues and the arbitrage will go away, even in places like California, after a couple of years.

The revenue model needs to improve if storage is going to go crazy, but so far, there is so much liquidity in the market that everything is getting built in any case.

Offtake Contracts

MR. MARTIN: People have been talking for the last several years about how the offtake arrangements for power projects have become so much more varied. For example, community choice aggregators in California signed 117 power contracts in the 12 months through October 2020. There were 8,200 megawatts of corporate PPAs signed last year through November, of which 79% were virtual PPAs, meaning they did not involve physical delivery of electricity.

Storage projects are coming to market with only 30% to 40% contracted revenue.

Sarah Slusser, what trends do you see in offtake arrangements?

MS. SLUSSER: In addition to what you just said, we see power being sold into liquid markets like PJM and ERCOT with hedges to put a floor under the electricity price. Financial hedge offtakers are a very big market for all developers, in addition to the virtual PPAs that you mentioned. And, of course, utilities in some of the newer markets are turning more heavily to renewables.

MR. MARTIN: Has there been any change over the last year in the level of utility interest in signing long-term contracts to buy electricity?

MS. SLUSSER: The change we are seeing is a move to shorter-term contracts for by existing customers. Both the CCA and hedge provider markets have been growing bigger and bigger. Corporate PPA tenors are growing shorter.

MR. MARTIN: Short-term means less than 10 years?

MS. SLUSSER: No, 10 years is probably the shortest.

MR. MARTIN: To what extent are utilities in the market now looking for power?

MS. SLUSSER: It is most noticeable in the Southeast. Dominion continues to run competitive auctions. There are retail suppliers in Texas looking for renewables. Utility demand for renewables will continue to grow.

MR. MARTIN: Was there a period when utilities were out of the market and now they are returning as electricity purchasers?

MS. SLUSSER: It does feel like a resurgence of interest for renewables from the utilities, absolutely.

MR. MARTIN: It seemed during early 2020 like interest among corporate customers had cooled. Wholesale electricity prices have fallen significantly in recent years. Corporations with existing PPAs were not happy about having locked in high prices.

Have they come back into the market? Were they ever out?

MS. SLUSSER: We are seeing strong interest from corporate buyers. It is not just from the top companies, not just the FAANGs, but demand is also broadening into the second and third tier of potential buyers.

MR. MARTIN: To what do you attribute the increasing demand?

MS. SLUSSER: Primarily ESG, as well as the fact that you can lock in a low cost power for 30 years.

MR. BRANDT: Keith, two comments. / continued page 36

New Trends

continued from page 35

First, the reason that hedges and virtual corporate PPAs have tended to be for 10 years is that is what the tax equity market wanted. It would not do the deals otherwise. Lately, the out-year electricity price forecasts have been so pessimistic that more and more developers want to do shorter-term offtake contracts and take more merchant risk.

Comment number two is that while the FAANGs were the corporate buyers in the past, we are now seeing pipeline companies and others with big carbon footprints moving to sign corporate PPAs as a way of displacing their carbon footprints.

MR. MARTIN: Explain "FAANG" for our audience.

MS. SLUSSER: Facebook, Amazon, Apple, Netflix and Google.

MR. MARTIN: Jon Bram, you heard Ted Brandt say that developers, whose basic DNA makes them optimists, would rather have a limited contracted revenue stream and keep the upside on the out-year electricity prices. How do you view that as an investor?

MR. BRAM: We see the customers under corporate PPAs becoming a lot more sophisticated in their ability to allocate risk to the developers. Our bias, especially if you have a successful developer who every year is creating more projects, is not to speculate on out-year prices.

There are some developers who only want to contract for the bare minimum period required to get a project financed. That has not been our preferred approach.

On the other hand, in some projects where electricity is being sold into a liquid market and there is a long-term hedge, you can have very material electricity basis and shape risk. Over-contracting a variable resource can be as speculative as under-contracting.

We have to spend a lot of time stress testing all of the projects in which we invest because the customers are becoming much more sophisticated.

Another thing we see is more and more utilities wanting to sign build-transfer agreements — rather than PPAs — where the utility takes the project at the end of construction. That makes sense for them because they are trading fuel for steel that they can put in rate base. As long-term investors, we are not as keen on these arrangements, but from a developer's standpoint, the transactions offer attractive margins.

Green Hydrogen

MR. MARTIN: Let's talk about green hydrogen, which has been the rage lately in the trade press. It means using renewable energy to power electrolyzers to split water and hydrogen in water.

Ammonia fertilizer factories and oil refineries use hydrogen today as part of their manufacturing processes. Hydrogen fuel cells use them for specialty vehicles like forklifts, but the potential big play is for energy storage. Hydrogen can be used to shift energy usage across whole seasons rather than just from off-peak to peak hours in the same day. It is also expected to power heavy vehicles like trucks, buses and trains.

Himanshu Saxena, this is not on your top four things to chase this year, but how bullish are you about hydrogen and over what time period?

MR. SAXENA: We are in the process of building an ammonia project in Texas. That project will take about three and a half years to build, so it should be completed by the end of 2023. It is one of the largest ammonia projects in North America. We will buy hydrogen and nitrogen from suppliers, convert it into ammonia and put the ammonia on big ships to sell into the global market.

Almost every new utility-scale solar project is being bid with storage.

The reason we made an ammonia investment is because it is a proxy for a hydrogen investment.

Because of that project, we have been thinking a lot about both blue and green hydrogen. Green hydrogen is obviously the cheapest to produce, but blue is where we think most of the activity will be. Producing completely green hydrogen is actually really hard because creating base-load renewable energy so that the electrolyzers can run 24/7 is expensive.

The biggest variable in producing hydrogen is the capital cost of electrolyzers, and the second biggest variable is the cost of renewable energy. If you can buy renewable electricity for $20 a megawatt hour versus $30 or $40 a megawatt hour, it makes a world of difference in the price at which the hydrogen can be sold for the numbers to work.

From everything we have seen lately, the cost to produce blue or green hydrogen is still in the range of $7 to $10 a kilogram, and that is not cost-competitive. That is equivalent to a price of well north of $10 an mcf for gas. As a replacement fuel, hydrogen numbers still do not work.

The numbers have to drop below $2 a kilogram. For that, you need the cost of renewable energy and, more importantly, electrolyzers to come down.

Watch the two cost curves over the course of the next several years. Just as with LNG, the first deals that got done look expensive in hindsight. The early hydrogen buyers will pay $6, $7 or $8 a kilogram. Over time, the price will drop to $2 to $3 a kilogram.

We think there is opportunity in this market, but the buyer base is really limited today. A few discrete deals will get done over the next few years, but the market will really not start to grow until the latter half of the decade.

Tax Equity

MR. MARTIN: Ted Brandt, many developers told us last year that they were having trouble raising tax equity. There were signs at the end of 2020 that things were improving. Have they improved?

MR. BRANDT: My sense is that good projects are getting done, and some new investors have come into the market. In the fourth quarter, we represented Nestlé on making a tax equity investment in a Texas solar project. My sense is 2021 will be slightly better than 2020. That said, there is a hierarchy of developers. The tax equity is going to the A and B+ developers. The smaller developers are really struggling.

MR. MARTIN: Sarah Slusser, does that sound right?

MS. SLUSSER: Yes. COVID affected the supply of tax equity. Tax equity investors were unsure what tax capacity they would have in 2020 and 2021. That delayed things quite a bit. With a vaccine now in place, there is a lot more clarity about the economy. I expect things to improve this year.

MR. MARTIN: The US dollar lost 7% of value last year against a basket of peer currencies. Goldman Sachs expects a further 5% erosion this year. Shipping costs from Asia have soared. Rates to the US West Coast are now double what they were a year ago. A lot of renewable energy equipment is manufactured overseas. Is this a big deal?

MR. SAXENA: There are definitely cost pressures. Whether we are building transmission lines, an ammonia factory, new wind or solar projects or a gas-fired power plant, we see pressure on commodity prices like the price of steel, and a lot of that is connected to the dollar exchange rate.

We do see further upward cost pressures in 2021. People looking to build in 2021 or 2022 are going to have to factor in an appropriate potential further increase in commodity prices. Most people are not in a position to lock in prices while projects are being developed, especially early in the development phase.

Look forward and say, "The price of steel is $X, but by the time I put in an order, it will be 1.2 times $X because the dollar will have deteriorated." That is what we are doing, and I think others are doing it as well.

Uighurs

MR. MARTIN: I am going to roll through a lot of questions quickly.

Sarah Slusser, coming back to you: The New York Times over the weekend ran a story about how Chinese solar panel manufacturers in Xinjiang province may be using Uighur forced labor. More than a third of the global polysilicon supply used to make solar panels comes from that region. Congress could ban goods made with forced labor. How do you see this affecting the US solar market? How has it affected you?

MS. SLUSSER: We obviously don't support those terrible labor practices. We are putting measures in place to ensure that is not something in which we participate. In terms of the whole sector, the solar industry is moving to shift sourcing elsewhere.

MR. MARTIN: Jon Bram, the yield curve is growing steeper. The 30-year Treasury bond yield hit 1.875% on Friday. That's a 23-basis-point increase since the start of the year. Most debt in the project finance market is floating-rate debt. Do you foresee a move to lock-in rates, perhaps by refinancing with project bonds?

/ continued page 38

New Trends

continued from page 37

MR. BRAM: In our project businesses, we tend to fix rates. Because obviously you want to match your expense, which in renewables is primarily capital, to your revenues, which are often fixed.

So we have always been doing that, not so much with 30-year debt because if you look at a 15- or 20-year offtake agreement, your average life winds up closer to 10 years.

When the 10-year treasury is at 60 basis points, if you have not thought about hedging or locking that in, you are very unlikely to be happy one, two or three years from now. Our approach is to do that, and I think you will see more of that this year.

MR. MARTIN: Does anyone see a marked trend toward project bonds this year? [Silence.} I will take that as a "no."

Policy Upside

MR. MARTIN: There is clearly potential upside from government policy changes this year. A lot of the upside has already been priced into the market. But starting with what has already happened, Sarah Slusser, how big a deal were the year-end tax extenders for solar?

MS. SLUSSER: They were a really big deal. They lengthened our runway for the 26% investment tax credit by two years. With Biden and the Georgia Senate results, there may be further extensions.

MR. MARTIN: If any of you could put one policy change on the to-do list of the new Democratic-controlled Congress, what would it be? What would have the biggest impact?

MR. SAXENA: Make the tax credits refundable.

MS. SLUSSER: I agree. I think direct pay is the number one.

MR. SAXENA: Do it for carbon capture or section 45Q credits as well. There are so many industries that are going to benefit from it. There is no reason to pay a massive friction cost to somebody to monetize tax credits. That just makes no sense.

MR. MARTIN: Himanshu Saxena, you said in a September interview that you are chasing four sectors: transmission, storage, midstream opportunities and carbon capture. We talked a bit about carbon capture. Transmission projects are notoriously difficult to build. They have regulated returns. Are you expecting any policy changes to help?

MR. SAXENA: I think the policy changes that help renewables, will end up also helping transmission. For example, to the extent policy changes lead to more rapid retirements of coal-fired power plants, that affects transmission.

Any time you remove big sources of generation, or start putting in a lot of distributed generation, you have to assess the effect on the grid.

These are second-order effects. We do not expect any direct new policies to help with transmission, but transmission will benefit indirectly.

It is really hard to develop transmission. We are developing a project in California that has already taken five-plus years to develop, and when the development is done, it will take another year to build.

The ratio of development time to construction time — at five to one — is completely upside down compared to wind and solar, where the ratio is closer to one to one or two to one.

We think this ratio needs to narrow to improve things in that sector. Any support from states or stakeholders that are enabling the transition to a greener economy would be very helpful.

A lot of ESG-focused foundations and investors have come into the market and said, "We want to support transmission developers, because we see transmission as an enabler for a broader greening of the economy, and we value that." Things are heading in the right direction, but the ratio I mentioned has to improve before there will be major growth in the sector.

MR. MARTIN: Anyone interested in building transmission should read Superpower by Russell Gold, a Wall Street Journal reporter. It is the story of Clean Line Energy Partners, Michael Skelly's company, and the challenges of building new transmission lines. A single person can hold up a major multi-state project. In this case, it was a local politician in Arkansas.

Property and casualty insurance premiums have increased as much as 400% in the last two years in the solar market, and some coverages are not available at any price. Wildfires have pushed Pacific Gas & Electric into bankruptcy. What other effects are any of you seeing from climate change?

MR. BRAM: The wildfires made it really hard to operate plants. People could not get around in California. Solar projects were affected as smoke from fires dramatically reduced the amount of sunlight reaching solar panels in some locations.

MR. BRANDT: One effect of escalating insurance premiums is people are looking at doing insurance differently: for example, by setting up captive insurance companies and effectively leaving the first-mile risk in the sponsor's hands. We are watching that trend.

MR. SAXENA: It is not just wind and solar where insurance costs have increased, but we see that across the portfolio. The cost of procuring insurance for gas-fired power plants has increased. When insurance companies have to pay large claims after strong hurricanes, wildfires and 500-year floods, they have to increase premiums across the board to cover the cost.

MR. MARTIN: So it is not just the projects that are in hurricane or tornado alleys or flood zones that are being affected by climate change because the entire insurance market is suffering.

SPACs

MR. MARTIN: Switching to M&A, Ted Brandt, you said on a panel that you and I did in May 2020 that the M&A market went through a short-term storm. When the COVID lockdowns started, the financial players pulled back because they could earn the same returns on offer in projects by investing in liquid instruments with less risk. However, you said there was no pullback by strategic investors.

What do you expect this year? Will both financial and strategic investors be in the market with both feet?

MR. BRANDT: In the past when we thought about putting assets or a development platform out for bid, we would ask ourselves whether it was more likely to go to a financial or a strategic investor. You would strum both strings on the guitar, and that would be the process.

The fact that there are more than 100 fully funded SPACs out looking for a dance partner really has changed that calculus. All of a sudden, we are finding that clients want us to see whether we can find a SPAC dance partner as an alternative to a private capital raise or an M&A deal.

That is a major, major change. SPACs have been around for a number of years, but nothing like last year when $82.1 billion was raised. Some amazing amount of capacity in the PIPE market is also available.

MR. MARTIN: SPAC stands for "special-purpose acquisition company." People often call them blank-check companies. Money is raised on a stock exchange and then the SPAC goes in search of a target. I thought they were simply a faster means to go public, but you are describing a broader role for them as a general source of equity.

MR. BRANDT: That is certainly the way I look at them. Yes, they are a faster way to go public, but you also get to know your price when you sign a term sheet as opposed to the classic IPO process, which is not all that much fun.

Most people who go through that traditional process say the process really stinks. You don't know your price. You don't know where the lead underwriter is going to come in, and you almost always have to depend on the secondary market because you never get the whole business plan funded.

SPACs have been a pretty interesting response to that. I call it a different way to raise equity rather than just a faster way to go public.

MR. SAXENA: I think the big difference also is the fact that you can rely on growth projections a lot more when you use a SPAC to go public. That fundamentally changes how you market a SPAC versus a traditional IPO.

All of the SPAC targets are heavy growth companies with 30%, 40%, even 50% compounded growth rates year on year. It is far harder to pitch such growth in the traditional public IPO market than it is to a SPAC. It is just not the same product.

MR. MARTIN: Stem, which is a storage software company, will merge into a SPAC in the first quarter this year. All of this money chasing deals should drive down returns.

Jon Bram, the organizers of SPACs generally take about 20% of the target once they find one. Does this have staying power?

MR. BRAM: The fees are higher than in the IPO market, but they are coming down over time.

SPACs would seem to have staying power, at least in the near term. SPACs raised something like another $7 billion just in the last week. There is a lot of pent-up capital looking for these growth investments. To Himanshu's point, the ability to market off projections is fundamentally different than the IPO process.

MR. MARTIN: Ted Brandt, before we leave M&A, what are current discount rates for bidding for contracted wind and solar assets?

MR. BRANDT: For contracted projects that are pre-NTP — they are not yet under construction — we are seeing unleveraged after-tax rates of sub 6% for solar and sub 7% for wind. The leveraged rates are not that different for operating projects.

A big factor in how much someone is prepared to bid is expectations about future power prices because there is so much of a merchant component on a solar project with a 35-year useful life. There is a lot of cynicism among investors today about future power prices. In many cases, the future power price assumptions are way more powerful than the discount rate.

MR. MARTIN: Jon Bram, Ted tends to be on the sell side. You tend to be on the buy side. Do those discount rates sound right to you?

/ continued page 40

New Trends

continued from page 39

MR. BRAM: We are on both sides because everything we buy, we subsequently sell at some point.

Discount rates are hard to compare because you would use a different rate for a hedged project selling on a merchant basis into the grid than for one with a 20-year PPA. The price for a west Texas solar project on the wrong side of the GTC transmission constraint is different than for a solar project in the Pacific Northwest.

Assumptions about future power prices are becoming more important than discount rates to win bids.

What is clear, though, is the rates of return have compressed by at least 100 basis points in the last 12 months.

MR. MARTIN: Switching gears, the major oil companies are talking about an energy transition. Many of them have moved into offshore wind where their experience with offshore drilling may help. Do you see them becoming significant players in renewables beyond offshore wind and, if so, where?

MR. BRAM: I do because of their ability to trade power. I think they are naturally well suited for onshore projects.

MR. SAXENA: It would not be the first time they have made inroads into renewables. BP and Shell have been in and out of the renewables business over time. Pressure from shareholders is causing them to take another look. They know how to build, own and operate renewables projects.

MS. SLUSSER: Shell just increased its investment in Silicon Ranch, a solar developer, last year.

MR. MARTIN. Another question. Jon Bram, I read that GIP, your company, raised $2.8 billion in early December for two infrastructure credit funds. GIP Credit, which I think stands for the two funds, has already announced four investments, three of them in Latin America — a Columbian port, Uruguayan railroad and Mexican IPP — and one is a natural gas pipeline in the US. These all seem bets against conventional wisdom. Do you expect deal flow to pick up this year in Latin America?

MR. BRAM: We have about $5 billion managed in our credit business that sits alongside our main equity funds. Those deals were not really counter to conventional wisdom. They were pretty much straight-up, classic project finance transactions with which most people would be very comfortable.

One was upgrading railroad in a government public-private partnership. Another is a newly-built port to support farm exports out of Columbia. The Mexican IPP is classic holding company debt. We can mobilize reasonably large amounts of capital that banks may not be set up to do on fixed- and floating-rate basis. The demand for that type of capital has been fairly strong for smaller deals in the $200 million to $300 million range that are not down the fairway. Banks are more choosey. We can provide transitional capital at reasonable returns.

Green Bonds

MR. MARTIN: I have three more quick questions and then we will go to audience questions.

Ted Brandt, do you expect green bonds or sustainability-linked bonds to get more traction in the US market? Sustainability-linked bonds reward or penalize issuers for hitting or missing environmental targets. To date, both have found more favor abroad than they have in the US.

MR. BRANDT: We have not seen much demand for them, but we are exploring them for a client now. You may have asked the perfect question earlier, which is whether a steeper yield curve will cause CFOs to turn to fixed-rate bonds in place of floating-rate bank debt. At least for the last couple of years, the answer to that has been “no.” Bank debt has been so attractive that it is where 90% of the market has been going.

MR. MARTIN: Bank debt should remain attractive as long as there are so many banks chasing deals. This keeps downward pressure on rates.

MR. BRANDT: It sure seems like that. Sarah Slusser proved that holdco debt that maybe a year ago was done by the non-bank mezzanine lenders is now being done at literally half the spreads by the banks.

MR. SAXENA: We have not seen much difference in pricing between a normal bond and a green bond. It is not as if a borrower will get capital that is 25 or 50 basis points cheaper by turning to green bonds. There has been a lot of chatter about green bonds, but from a borrower's standpoint, it is hard to justify the amount of work and the obligations you take on by issuing green bonds for a not-very-meaningful reduction in cost of capital.

MS. SLUSSER: Traditional power projects were hard to finance in the bond market because of the negative arbitrage during the very long construction periods for those types of projects. This is not as much of a problem for solar projects with construction periods of less than a year. If there were a meaningful difference in borrowing costs between bank debt and green bonds, then green bonds would be attractive.

MR. MARTIN: Last question and then we go to the audience. Are there other trends that we did not discuss?

MR. BRANDT: Renewable diesel. This is an energy transition area where developers are trying to find contracts. The unleveraged yields are in the double digits.

MR. MARTIN: That's interesting. Two groups of Norton Rose lawyers submitted articles for our December Project Finance NewsWire on renewable natural gas without knowing that the other group was working on the same topic. How big a market do you foresee this year for such projects?

MR. BRANDT: Five or six? We were part of a big one last year in which Brightmark raised money from Chevron. Half the market sells into California whether the production facility is in Indiana or Oregon, but a non-California market is growing around the country. More and more utilities are getting involved as a possible new source of business for their local gas distribution companies.

Audience Questions

MR. MARTIN: Let's turn to audience questions. "Can you discuss build-transfer agreements versus PPAs?" Jon Bram, you already mentioned the move to BTAs. Is there anything you want to add?

MR. BRAM: When you approach a utility about repowering an existing wind farm, what we usually hear is relief that the PPA will end soon and interest in owning the project rather than entering into another PPA. Their priority is to invest in rate-base assets, preferably green rate-base assets.

MR. MARTIN: Sarah Slusser, you and I both had an association with AES. You were a top executive. We were the outside counsel for at least the first two decades. If you start with an IPP mindset, the fact that the market is moving to a build-transfer arrangements is a source of frustration, no? The utilities will not buy the power.

MS. SLUSSER: I am one of these all-of-the-above people. I am happy to develop projects and sell them to a utility under a build-transfer model, while other utilities or corporate customers want to sign PPAs. I am happy to have a mix. Our assumption is that we will sell half the projects that we develop and retain half.

MR. MARTIN: Next question. Himanshu Saxena, you and Sarah Slusser both mentioned that you would like to see refundable tax credits. An audience member asks, "Is that really a good idea? Won't that lead to the same delay, rule-writing and litigation that was associated with the section 1603 program?"

MR. SAXENA: The complexity and the cost of structuring tax equity deals is too great. You build a 100- or 200-megawatt solar project and you end up spending $2.5 to $3 million in legal fees.

There is too much friction cost with tax equity. We love our tax equity investors because we need them and they are good people, but they are making a pretty penny on these investments. If you want mass adoption of utility-scale and distributed generation renewables, there has to be a better way.

MR. MARTIN: Sarah Slusser, the solar industry tired of the section 1603 program after a while. Something like 27% of solar projects were told by the Treasury that they were using inflated tax bases to claim grants. Why dive back into that world?

MS. SLUSSER: I think the industry learned its lesson and would not go back in with such an aggressive stance. Direct pay is much simpler. The full subsidy goes where it is intended.

MR. MARTIN: Next question. "ESG seems to be on everyone's mind. How easy has it been to raise capital for these types of projects and what are investors weary of when looking at ESG investments?"

MR. BRAM: There is a whole different level of reporting and awareness. We have added a lot of people just to deal with collecting, managing, and presenting / *continued page 42*

New Trends

continued from page 41

this information to our investors for whom this is important. They are focused on returns, but they are also focused on sustainability. With that comes reporting.

MR. MARTIN: Next question for Ted Brandt. "How significant is the Xinjiang Uighur issue among the finance community? Is something being tracked and potentially priced as a risk factor to projects sourcing supply from China?"

MR. BRANDT: It is an emerging issue. We are all trying to figure out what the new administration will require. ◎

Partnership Flips

by Keith Martin, in Washington

Partnership flips are used to raise tax equity in the US renewable energy market. They are not the only structure for doing so, but they are the most common, and they are the only way to raise tax equity for wind farms and other projects on which production tax credits will be claimed.

This article describes how the structure works and current issues that are taking up time in partnership flip transactions.

The US government offers two tax benefits: a tax credit and depreciation. They amount to 44¢ to 49¢ per dollar of capital cost for the typical wind or solar project that was under construction in time to qualify for tax credits at the full rate. Few developers can use the tax benefits efficiently. Therefore, finding value for them is the core financing strategy for many US renewable energy companies.

Tax equity accounts for 65% of the capital stack for a typical wind farm, plus or minus 10%. It accounts for 35% for a typical solar project, plus or minus 5%. The percentages should increase if, as expected, Congress increases the corporate tax rate from the current 21% to between 25% and 28%.

The developer must fill in the rest of the capital stack with debt or equity.

More than 40 tax equity investors did transactions in the 18 months before the COVID-19 lockdowns started in March 2020. Many developers had a hard time finding tax equity during 2020, and 2021 is expected to remain a challenging year. Competition from $3-to-$6 billion offshore wind projects and from a potentially rapidly growing market for carbon capture projects that qualify for section 45Q tax credits is expected to add to the challenges.

Renewable energy tax equity was a $12 to $13 billion market in 2019. It was $17 to $18 billion in 2020. Two banks – JPMorgan and Bank of America – accounted in both years for more than half the market.

The renewable energy trade associations are urging Congress to allow owners of new renewable energy projects to apply for refunds from the IRS for the tax credits. Any such change would be part of a clean energy and infrastructure bill that is expected to move through Congress by early fall. If such a provision is enacted, developers are still likely to turn to the tax equity market for financing as they did during the period 2009 through 2016 when the US Treasury was paying the cash value of the tax credits as an Obama economic stimulus measure. Tax equity will still be needed to monetize tax depreciation on the projects, and the tax equity market acts as a source of bridge financing for the tax credits until the cash payments are received. Several large banks came back into the tax equity market during the Treasury cash grant era despite lacking tax capacity.

Simple Concept

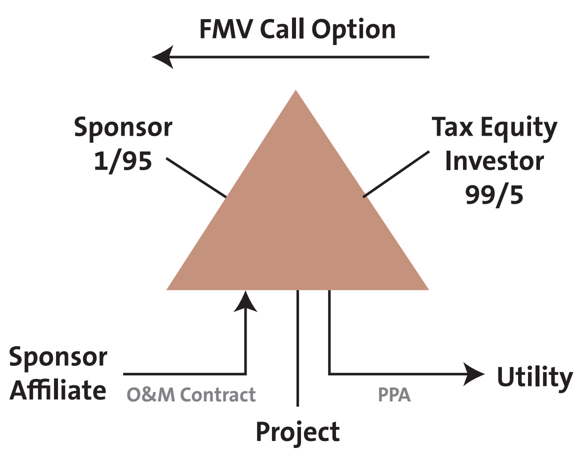
Partnership flips are a simple concept. Tax benefits can only be claimed by the owner of a project. Partnerships offer flexibility in how economic returns can be shared by the partners. A developer finds an investor who can use the tax benefits. The two of them own the project as partners through a partnership.

All wind deals and about 80% of solar deals are yield-based flip transactions.

In the typical such transaction, the partnership allocates 99% of income, loss and tax credits to the tax equity investor until it reaches a target yield. Cash is shared in a different ratio. After the yield is reached, the investor's share of everything drops to 5% and the developer has an option to buy the investor's remaining interest.

The typical structure is shown in Figure 1.

Figure 1: Basic Yield Flip



Developers like partnership flips because they get back 95% of the project without having to pay anything for it.

In some deals, the investor takes as little as 2.5% of the cash after the flip, but this is uncommon.

The sponsor call option is usually for fair market value, although the IRS allows a fixed price that is a good faith estimate at inception of what the value will be when the option is exercised. Some developers require the investor to pay enough to avoid a book loss on sale. Sometimes the option can be exercised before the flip, but not before five years have run after the project is placed in service. Any option before the flip must pay the investor enough at a minimum to get the investor to its target yield.

The developer retains day-to-day control over the project. A list of major decisions requires consent from the tax equity investor. In some deals, the list is shorter after the flip.

Many investors use hypothetical liquidation book value, or "HLBV," accounting to account for their investments. This requires tracking what the investor would receive at each year end if the partnership liquidated. The difference in amount from one year to the next is added or subtracted from earnings.

The Internal Revenue Service published guidelines in 2007 for partnership flip transactions. The guidelines are in Revenue Procedure 2007-65. Some revisions were made two years later in Announcement 2009-69. Most transactions remain within the guidelines.

The individual guidelines that are most likely to come into play are that the tax equity investor must retain at least a 4.95% residual interest after the flip, the flip cannot occur more quickly than five years after the project goes into service, any option to buy the investor's interest must be for fair market value or a fixed price that is a good-faith estimate at inception of what the fair market value will be at time of exercise, the investor must make at least 20% of its total investment before the project is put in service, and the investor cannot have a "put" to require the sponsor to purchase its interest.

The guidelines bar guarantees of production tax credits by anyone, including third parties, and the developer, turbine supplier and electricity offtaker cannot guarantee the output for the investor.

Most investors want to see at least a 2% pre-tax or cash-on-cash yield. The market treats tax credits as equivalent to cash for this purpose.

The IRS said in an internal memo released in June 2015 that the flip guidelines do not apply to solar projects or other projects on which investment tax credits are claimed. The memo said to apply general partnership principles to test whether the investor is really a partner. It is CCA 201524024. (For more detail, see "The Partnership Flip Guidelines and Solar" in the July 2015 *NewsWire*.)

The investor must not walk so close to the line as to be considered a lender or a bare purchaser of */ continued page 44*

Partnership Flips

continued from page 43

tax benefits. A lender advances money for a promise to repay the advance plus a return by a fixed maturity date.

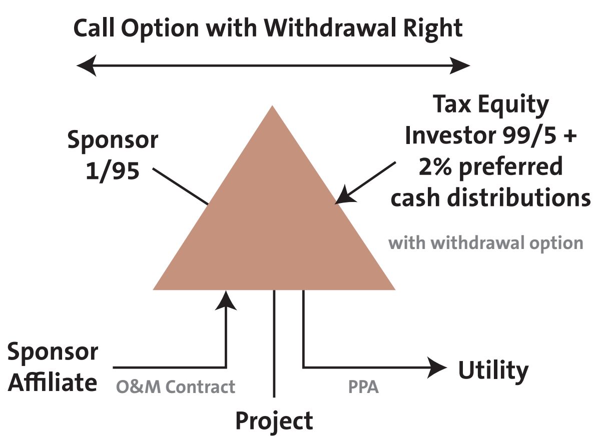
Variations

There are several variations in forms of partnership flip transactions.

At least one major investor uses a fixed or time-based flip structure. The investor flips to a 5% interest on a fixed date, usually after five to five-and-a-half years. The developer has a call option. The tax equity investor has a withdrawal right six months to a year later if the call is not exercised.

The investor in a fixed-flip transaction receives preferred cash distributions each year equal to 2% of its original investment and some percentage of remaining cash. Developers like this structure because it lets them retain as much cash as possible. Developers would rather borrow against future cash flow at a lower debt rate than a tax equity yield.

Figure 2: Fixed Flip



An area of tension in fixed-flip transactions is how quickly the partnership must pay the market value of the investor's interest after it withdraws from the partnership. Most deal documents give the partnership two years. The withdrawal amount is paid out of partnership cash flow. If the full price is not paid within two years, then the investor can take the project. This can also create tension with any back-levered lenders who have made a loan to the developer against its expected cash distributions from the partnership.

Another source of tension is the developer ends up with a negative capital account because it keeps most of the cash. Many tax equity investors now require the developer to agree to put cash back into the partnership if the developer still has a negative capital account when the partnership liquidates.

Another common variation on the standard flip is a pay-go structure used in wind and geothermal deals with production tax credits. The investor makes 75% of its investment at inception or as a fixed amount over time, and the other 25% is tied to production tax credits the investor is allocated each year. The IRS flip guidelines limit the amount of investment that can be tied to output or tax credits to 25%. Investors were originally not keen on pay-go structures because they preferred to earn a return on the full investment from inception. However, they have gained in popularity as a way to mitigate operating risk and the risk that the tax law will change.

Most uses of the pay-go structure lately have been as a way for sponsors to get additional value for remaining production tax credits after the investor has already reached the flip yield. The pay-go payments are made in the post-flip period from the flip date through the end of the 10-year period for claiming production tax credits.

Absorption Problem

Almost all partnership flip transactions have an "absorption" problem. Each partner has a "capital account" and an "outside basis." These are two ways of tracking what a partner put into the partnership and is allowed to take out.

Once the investor's capital account hits zero, then its remaining share of tax losses shifts to the developer.

Once its outside basis hits zero, then any further losses it is allocated end up being suspended. They can be used only against future income the investor is allocated by the partnership. Any cash it is distributed is considered an "excess cash distribution" and must be reported as capital gain.

There are two ways to deal with an inadequate capital account. One is for the investor to agree to a "deficit restoration obligation" or "DRO." This is a promise to contribute more money to the partnership when the partnership liquidates to cover any negative capital account. On that basis, the IRS will let the investor absorb more losses. However, the investor may still have too little outside basis to absorb them immediately. Suspended losses should not count toward the flip yield until used.

The IRS will ignore a DRO if there is a "plan to circumvent or avoid" the obligation to contribute more capital. There should be "commercially reasonable provisions for enforcement and collection of the obligation," and the partner should be required to provide documentation regarding its financial condition. The practical effect is to impose a net worth test on the sponsor to ensure that it can satisfy the DRO. (For more details, see "Tax Equity and DROs" in the October 2016 *NewsWire* and "Deficit Restoration Obligations" in the December 2019 *NewsWire*.)

DROs today can reach 50% to 70% of the tax equity investment. Falling wholesale electricity prices are forcing them to these levels. Investors who agree to DROs usually want to be allocated income as quickly as possible after the flip to reverse the deficit and to be distributed cash to cover the taxes on the additional income.

Tax equity accounts for 35%, plus or minus 5%, of the capital stack for a typical solar project.

Such post-flip measures could turn the original 99% allocations to the tax equity investor into "transitory allocations" if they are reversed within five years. The IRS does not allow transitory allocations.

An investor usually places a dollar limit on the DRO to which it has agreed.

Some investors wait to see how a year went and then increase the DRO after the year ends. Partnership allocations for a year can be adjusted retroactively up to the due date for the tax return for the year (not including extensions). In most deals, once the deficit starts to contract, the cap on the DRO goes down as well.

In fixed-flip deals where the developer ends up with a negative capital account, many tax equity investors require the developer to agree to a DRO. This makes the promise that the developer will be able to keep most of the cash somewhat illusory, since the developer may have to recontribute cash to the partnership. Special measures to reverse the developer deficit are rare.

Another way to address the absorption problem is to add project-level debt. This turns part of the depreciation into "nonrecourse deductions" that can be taken by partners even after they run out of capital account. The debt also increases the investor's outside basis.

Partners taking nonrecourse deductions must be allocated an equivalent amount of income later as the debt is repaid, thus turning the nonrecourse deductions truly into a mere timing benefit. These later allocations are called "minimum gain chargebacks." The partnership earns revenue from selling electricity. The partners must report the income. However, the cash goes to the lender to pay debt service, leaving the partners with "phantom" income: income but no cash distributions to cover taxes on the income. The minimum gain chargebacks are allocations of this phantom income. Chargebacks are not additional income, but rather an override on how some of the income the partnership is already allocating to partners must be allocated.

Almost all debt in the market today is back-levered debt behind the tax equity in the capital stack. If there is project-level debt, then the tax equity investor will demand a higher yield and require the lender to enter into a forbearance agreement. In contrast, lenders are not charging any premium to lend on a back-levered basis due to the intense competition among banks to lend.

A tax equity investor might take other steps to make it less likely that its capital account will go negative. These include reducing its share of income and losses in a solar deal from 99% to 67% in the year after the project is placed in service and then moving back to 99% in the year the partnership starts generating taxable income or taking depreciation on the project on a straight-line basis over 12 years.

The IRS requires that a third metric / continued page 46

Partnership Flips

continued from page 44

called "tax capital" be tracked and reported each year starting with K-1s sent to partners in 2021 for the 2020 tax year. This is a hybrid between capital accounts and outside basis. It is a way for the IRS to identify partners who may have taxable gains to report. Negative tax capital is a sign of a potential gain. (For more detail, see "Partnership 'Tax Capital'" in the June 2020 *NewsWire*.)

If not already clear, it is important to model what will happen inside the partnership. The business deal may be to allocate income, losses and tax credits 99% to the tax equity investor, but that is usually not what will actually happen. (See "Calculating How Much Tax Equity Can Be Raised" in the June 2008 *NewsWire* for help with how to model the deal.)

The amount of tax equity raised through a flip transaction is the present value of the discounted net benefits stream to the tax equity investor. The investor receives three benefits: tax credits, cash and tax savings from losses. It suffers one detriment: taxes have to be paid on the income it is allocated. It discounts these amounts using its target yield to a present-value number.

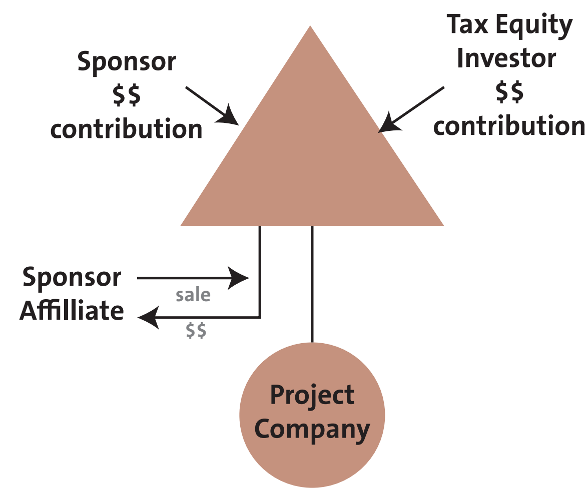
Putting the Structure in Place

There are three ways to put a partnership flip transaction in place.

The most common approach today is a "project-company-sale model" where the developer sells the project company near the end of construction to the tax equity partnership. Both the developer and the tax equity investor contribute capital to the partnership to pay the purchase price. The project is sold for the appraised fair market value the project is expected to have at the end of construction.

In solar deals, the partnership usually pays 20% of the purchase price at mechanical completion before any part of the project is in service and the other 80% after the entire project is in service. This begs the question what happens if the conditions for the 80% payment are not met. In many deals, the partnership has a "put" to require the developer to buy the project back from the partnership for the 20% payment plus a return. However, the right to sell back lapses automatically once any part of the project has been placed in service. If the unwind right has lapsed, then the tax equity pricing model is rerun and the ratios for sharing economic returns inside the partnership between the developer and tax equity investor are adjusted because the investor will retain full ownership while having only made a fraction of its expected investment.

Figure 3: Project Company Sale Model



Another way to put the structure in place is a "contribution model" where the project company is already owned by the partnership and the tax equity investor makes a capital contribution to the partnership in exchange for an interest. The capital contribution may be used by the partnership to pay the EPC contractor or pay off construction debt, or it may be distributed to the developer.

Figure 4: Contribution Model

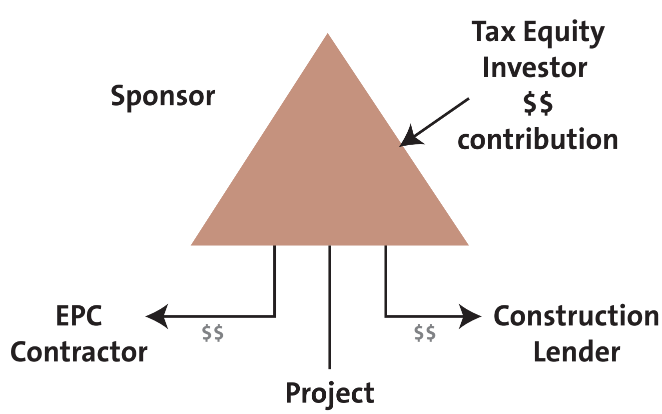
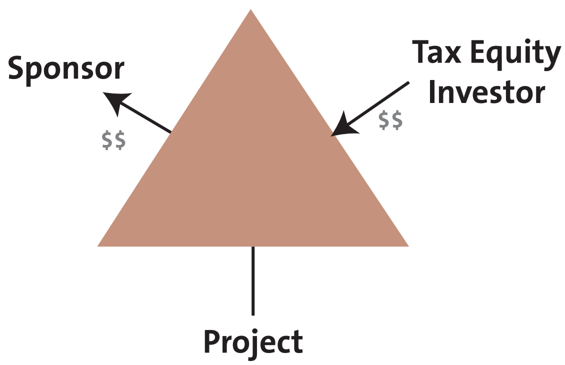


Figure 5: Contribution Model with Distribution Out

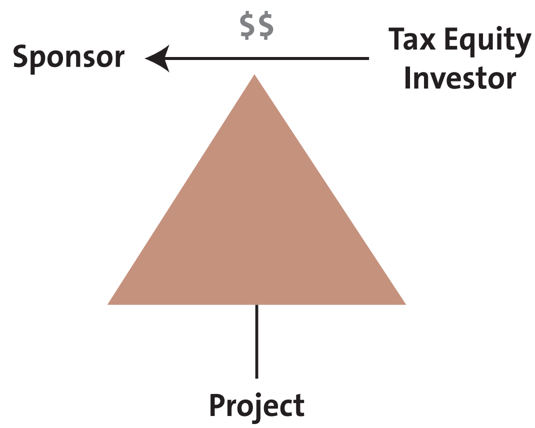


The developer may be able to pull out the tax equity raised as a tax-free return of capital. The key is to avoid having the distribution out labelled by the IRS as a "disguised sale" of the project to the partnership. It must fit in a "pre-formation expenditure" safe harbor that lets the developer be reimbursed for its capital spending on the project over the last two years.

The project cannot be worth more than 120% of the tax basis the developer has in the project when the partnership is formed to make full use of this safe harbor. If there is debt on the project when the tax equity investor makes its first capital contribution, then it will complicate the calculations to determine whether the safe harbor applies. (For a discussion about how the safe harbor works, see "Tax Triggered When Partnership Formed?" in the October 2016 *NewsWire*.) Any developer planning to use the safe harbor should make sure the partnership agreement says that the distribution of the tax equity contribution to the developer is a reimbursement of pre-formation expenditures within the meaning of section 1.707-4(d) of the US income tax regulations.

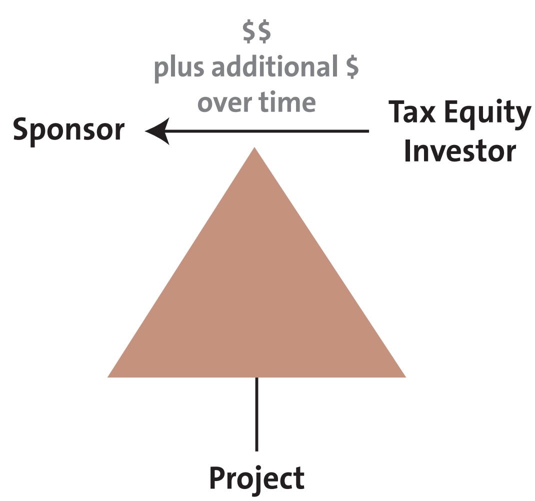
A third way to put the tax equity partnership in place is a "purchase model" where the tax equity investor pays the developer directly for an interest.

Figure 6: Purchase Model



In a pay-go variation on these structures, the tax equity investor pays an amount at the start to buy an interest in the project and makes additional payments over time that are a function of the output or tax credits. The contingent payments cannot be more than 25% of the total investment.

Figure 7: Pay-Go Structure



Back-Levered Tensions

There are a number of recurring issues in flip deals.

Many developers, particularly in the solar market, use back leverage to borrow against their shares of partnership cash flow. A back-levered loan is a loan to the developer against its share of cash flow from the partnership.

/ continued page 48

Partnership Flips

continued from page 47

This creates tension between the back-levered lender and the tax equity investor, particularly over any cash sweeps at the partnership level that could divert cash needed to pay debt service on the back-levered debt. Cash sweeps may come up in two contexts. One is where an indemnity has to be paid by the developer. The other is some tax equity investors have a cash sweep to get back on track, in a deal that is falling behind, to reach the target yield on the date originally projected.

Many investors are agreeing to limit the percentage of cash to 50% to 75% that can be swept in order to mitigate the risk to the lender. Some agree not to sweep an amount of cash equal to scheduled principal and interest payments on the debt.

Change-in-control issues also come up. The lender wants a right to foreclose on the developer's partnership interest after a debt default. The tax equity investor wants an experienced renewable energy operator as its partner and may impose net worth and experience requirements on any subsequent transferee of the interest. It would be a good idea for sponsors to get agreement from the tax equity investor on the terms of a consent by the tax equity investor to such a foreclosure and subsequent sale of the sponsor interest when the flip partnership closes, if the back-levered debt will be added later, to avoid costly and time-consuming negotiations later.

Other Recurring Issues

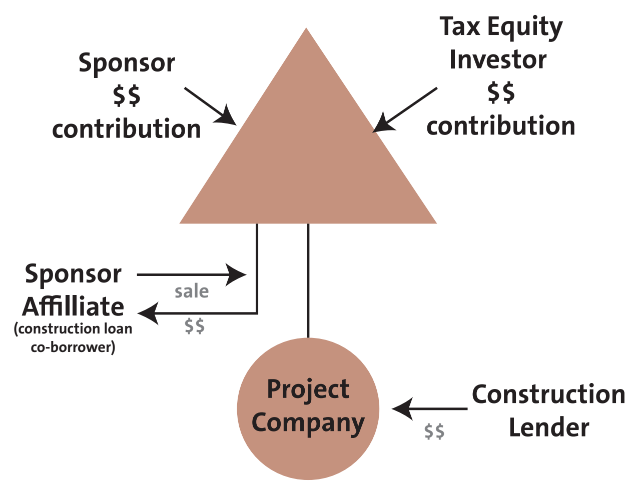
Developer fees are out of favor after the US Court of Federal Claims prevented Invenergy from adding \$50 to \$60 million developer fees to tax basis in two wind projects. The court said the fees were merely circled cash. (For more details, see "California Ridge: Developer Fees Struck Down – Again" in May 2020 *NewsWire*.)

Most audit activity in the solar market has been around the tax bases claimed in tax equity deals. Many tax equity investors limit the markup they are willing to allow above construction cost to 15% to 20%, although these limits are hard to enforce in practice. The IRS tends to focus on where the final basis per watt lands in relation to what it sees generally in the market.

Some tax equity investors are requiring tax insurance to cover basis risk in the residential rooftop market. Premiums on tax insurance generally run 2% to 3% of the potential payout.

Another issue in deals is how the construction debt converts into back-levered term debt. If the project company and an entity above it that sells the project company to the partnership are co-borrowers under the construction loan and the partnership buys the project company subject to the construction loan, the partnership may not be able to include the loan in tax basis if the seller remains liable for the debt. The seller should be released from the debt in order for the partnership to be able to treat it as having been assumed as part of the purchase price.

Figure 8: Project Company Sale Model



The market is wrestling currently with how to address risk of a change in tax law. Many deals require a repricing to reflect any change enacted through the end of the 117th Congress that runs through 2022. The tax equity investor does not have to fund unless any proposed adverse tax law change is reflected in the pricing. If the change is not ultimately enacted, then the investor may have to make an additional capital contribution. In some deals, the tax equity investor has a cash sweep to get back on track if any adverse tax law change delays the projected flip date by more than a year. The parties debate how far a proposed adverse tax law change needs to have advanced in Congress before the tax equity investor can use it as a reason to stop further funding.

A tax rate increase would mean more tax equity will be raised on future projects. It could delay or accelerate the flip depending on when during the life of the project it occurs. A rate increase shortly after a project is put in service would increase the value of the tax depreciation. A rate increase later in time will only increase the taxes that the tax equity investor must pay, thereby delaying the flip and increasing the cash the investor will take over time to get it to the flip yield. A higher tax rate could also ultimately increase the supply of tax equity, although how much is unclear. Tax equity yields are a function of demand and supply.

The tax equity investor bears the risk of tax law change in a fixed-flip structure. When Congress was considering reducing the corporate income tax rate in 2017, at least one fixed-flip investor asked developers for an indemnity to cover any loss in value of tax losses.

Tax equity investors have had little interest in the past in taking the 100% depreciation bonus on offer currently from the US government because they want to spread their scarce tax capacity over more deals. With the corporate tax rate expected to increase, developers are likely also to want to push depreciation into 2022 or later when it will be taken against the higher tax rate.

Investment tax credits must be shared by partners in the same ratio they share in "profits" in the year a project is put in service. The word "profits" in this context means income. The tax credits claimed by a partner will be recaptured if the ratio in which income is shared by partners leaves that partner with more than a one-third reduction in its share of profits during the first five years after the project is put in service.

Some investors reduce their share of losses to 67% after year one until the first year there are profits, when the percentage goes back to 99%. This puts less pressure on the investor capital account. The standard partnership agreement says that once a partner runs out of capital account (plus any DRO), then its remaining share of losses will be diverted automatically to the other partners. Many tax counsel believe such a loss shift will drag production tax credits in years when losses shift to the sponsor; the tax credits are shared in the same ratio that losses end up being allocated in fact in such years.

Some counsel worry that unvested investment tax credits may also be recaptured in years that losses shift if the tax equity investor ends up in fact with more than a one-third reduction in its share of losses in such a year. This position is not shared by most tax counsel. Many tax counsel are uncomfortable with a shift down that occurs quickly after assets are put in service. Thus, for example, in a deal where a solar project is put in service on December 28, many tax counsel will not want to see the tax equity investor reduce its share of profits to 67% on January 1. Most prefer to wait at least six months.

Many investors insist on holding the 99% income share for at least one full year — and sometimes for two years — of meaningful income lest the IRS say the first-year 99% allocation used to send 99% of the investment tax credit to the investor was illusory because it changed by the time there were profits.

Partnerships that generate and sell electricity must use the "inventory method of accounting." This means they can only allocate net income or net loss. They cannot disaggregate the elements that go into the calculation of net income and loss and allocate them differently. Income and loss from rooftop solar equipment that is leased to customers can be disaggregated and allocated differently.

Taxpayers cannot claim losses on sales to related parties. This means that a partnership cannot claim net losses in years when electricity is sold to a partner. In some partnerships owning merchant power projects, the developer must put a floor under the electricity price to finance the project. Any contract between the partnership and the developer should be a swap rather than a power purchase agreement, at least during the first few years before the partnership turns tax positive.

Some developers approach inappropriate parties as tax equity investors. Passive loss and at-risk rules make it hard for individuals, S corporations and closely-held C corporations to use tax benefits on renewable energy projects. A closely-held C corporation is one where five or fewer individuals own more than half the stock. Stock held by family members is combined. An investor who is subject to the passive loss rules can use tax credits and depreciation to shelter income from other passive investments, but what is considered passive income is limited. Interest received on debt instruments and dividends received on stock are not considered passive income for this purpose.

The IRS started making back tax assessments at the partnership level in the 2018 tax year. The IRS will be able to collect back taxes directly from the partnership.

Some partnership agreements direct the managing member to elect to "opt out" of audits at the partnership level, meaning that any audits of 2018 or later tax years would be of the partners directly. Developers dislike this option because they will remain on the hook for tax indemnities, but lose the ability to handle the IRS audits that may lead to an indemnity.

In many deals, a "push-out election" is made to push out any such liability to persons who were partners during the year under audit. However, partners will have to pay 2% extra interest on the back taxes if this is done. It is important in such cases to make clear that the back taxes will be pushed out to partners in a ratio that reflects how they agreed to share the tax risks giving rise to the back tax liability.

Some recent partnership agreements leave any liability for back taxes by default at the partnership level, meaning that the economic burden to pay these taxes */ continued page 48*

Partnership Flips

continued from page 49

will fall on persons who are partners years in the future when the partnership is audited. This may be after the flip. The partners should agree to make capital contributions in a ratio that reflects how tax risks were shared by the partners and to indemnities if one of the partners is no longer a partner by the time the audit adjustment occurs. (For more detail and what options partnerships have available to them, see "US Partnerships Get a Makeover" in the November 2015 *NewsWire*.)

Property taxes are an ever-present issue in transactions involving solar equipment in California. Any change in ownership of solar equipment after installation will trigger a property tax reassessment. The amount could be substantial. The flip in a partnership flip transaction can trigger a reassessment if it transfers control back to the developer. A partner has control if it owns more than a 50% profits and capital interest in the partnership. The focus is on whether the developer is acquiring control rather than on whether the tax equity investor is losing it. If the tax equity investor gets control at the outset, then a reassessment will be triggered by the flip, assuming the investor has less than a 50% capital interest by the flip date. If the investor still has a 50+% capital interest, then control will transfer when the capital interest drops below 50% after the flip or, at the latest, when the developer exercises its option to buy the investor interest.

A bill has been introduced in the California legislature to prevent flips from being considered a change in control. ◎

COVID-19 and Business Interruption Claims

by Aditya Rebbapragada, in Singapore

The British Supreme Court cleared the way in mid-January for companies that have suffered economic losses due to COVID-19 to collect on business interruption insurance policies.

The court clarified the tests that insured parties must satisfy to claim under such policies and overruled a significant judgment that the insurers relied on in the past to limit the scope of claims.

The Supreme Court decision brings a close to a test case that the UK Financial Conduct Authority brought in the British High Court in 2020 to test when COVID-related business interruption claims should be paid under various forms of policy wordings. (For more information, see "Covid-19 and Business Interruption Claims" in the October 2020 *NewsWire*.)

The case is called *FCA v Arch Insurance (UK) Ltd and others* [2021] UKSC 1.

Policy Wordings

Business interruption policies on which businesses are trying to collect for COVID-19 related claims have clauses that fall into three categories.

One type of clause is a diseases clause that covers losses if specified diseases occur within a specified vicinity of the business premises of the insured party.

Another clause is a prevention-of-access clause that would cover losses if the insured party is barred from using its business premises due to restrictions imposed by a government.

The last type of clause is a hybrid clause that covers losses from a combination of a disease clause and a prevention-of-access clause, such as when the spread of an infectious diseases leads to prevention of access.

The High Court said in its September 2020 decision that because of the widespread nature of the COVID-19 pandemic, disease clauses should cover COVID-19 related losses, regardless of whether there is an outbreak of the disease within the specified vicinity — for example, within a 25-mile radius of the business premises of the insured party.

The court also said that prevention-of-access clauses should be construed narrowly, although in some circumstances they should still cover COVID-related claims.

For hybrid clauses, the court said that the disease-related portion of such clauses should apply just as independent disease clauses would, although the application of the prevention-of-access portion of such clauses depends on the exact policy wording and the circumstances that led to prevention of access.

Both the Financial Conduct Authority and the insurers appealed the High Court judgment to the UK Supreme Court.

The Supreme Court did not agree with the High Court that COVID-19 related losses are covered by disease clauses in all cases. It said there must be at least one case of COVID-19 within the radius specified in the policy.

It said that an insured party would need to show an "inability to use" the business premises to collect under a prevention-of-access clause. This would be satisfied if either the business was unable to use the premises for a discrete part of its business activities or was unable to use a discrete part of its premises for its business activities. In both situations, there is a complete inability of use.

"But-For" Test

The insurers argued before the Supreme Court that a COVID-19 outbreak within the specified vicinity cannot be a cause of business interruption loss if the loss would not have been suffered "but for" the COVID cases. They said they should not have to pay a claim if the same interruption of the business would have occurred anyway as a result of other cases of COVID-19 elsewhere in the country. The Supreme Court rejected this.

The Supreme Court said the UK government's response to COVID-19 was a reaction to information about all the cases of COVID-19 in the country. The response was national in scope because the outbreak was so widespread. The court said it is unlikely there is an enclave covering the entire specified radius around any UK business that is entirely free from COVID.

The insurers wanted to establish that the "but-for" test was not satisfied by relying on a 2010 Commercial Court judgment in case called *Orient-Express Hotels Ltd v Assicurazioni General SpA* ([2010] EWHC 1186 (Comm)).

This case concerned a claim for business interruption loss arising from wind and water damage to a hotel in central New Orleans as a result of hurricanes Katrina and Rita in the autumn 2005.

The insurance policy was governed by English law. It provided cover against physical damage to property on an all-risks basis.

It also provided cover for loss due to interruption or interference with the business directly arising from physical damage to the hotel. A "trends clause" in the policy limited any claim to the loss due to business interruption that would have been suffered for a period after the physical damage if the physical damage had not occurred.

The Commercial Court said the hotel could recover loss resulting from physical damage to the hotel, but the trends clause prevented recovery for the loss of business resulting from damage to the area surrounding the hotel that made the hotel less attractive to customers.

The Supreme Court said the Orient-Express case was wrongly decided and overruled it.

It applied the same test as it did for the disease clauses and noted that business interruption loss arose because both the hotel and the surrounding area and other parts of the city were damaged by the hurricanes. Each of these causes was by itself sufficient to cause the business interruption.

In such a case when the insured peril and the concurrent uninsured peril arise from the same underlying hurricane or other event, then loss resulting from both perils operating concurrently should be covered as long as the policy does not specifically exclude the loss arising from one of the perils.

Pre-Trigger Losses

One point on which the Supreme Court disagreed with the High Court is trends clauses and reduced turnover of business suffered before the insured peril was triggered.

The High Court said that if there was a measurable downturn in business turnover due to COVID-19 before the insured peril was triggered, then it would be appropriate to take the continued downturn or increased expenses into account as a trend that is not covered by the policy as a business interruption loss.

This would mean that if as a result of public concern about contracting COVID-19 and the advice given by the UK government before the national lockdown on March 20, 2020, the turnover of a pub in the week ending on March 20 was only 70% of its turnover in the equivalent week of the previous year, no claim would be paid except to the extent of any post-March 20 further deterioration in business.

The Supreme Court said the High Court was wrong. It said when calculating loss, the full loss after the trigger event should be paid. That loss in the pub case would be the full downturn in business after March 20 compared to the base year. ◎

Tapping Equity in the London Market

by Richard Sheen, in London

London listings are being used by some investment managers to raise capital to invest in US renewable energy assets.

US manager, NextEnergy Capital, announced a planned £300 million raise in early February for a renewables investment trust that will invest in private funds run by both its investment manager and third-party firms as well as make co-investments and direct acquisitions of infrastructure projects.

Tortoise Ecofin launched the Ecofin US Renewables Infrastructure Trust PLC in December 2020 raising $125 million. This fund acquired a seed portfolio of solar projects serving utility and commercial offtakers in three US states shortly after its listing.

Both listings follow a pattern set by US Solar Fund PLC, which launched in 2019 with an Australian manager, New Energy Solar, and raised £200 million to invest primarily in North American solar assets.

London has become popular for such listings because of the relative efficiency of raising capital and the access to a wide pool of knowledgeable investors with an appetite for renewable energy assets.

Investors in these types of funds typically expect a progressive annual dividend yield of more than 5%, and such funds usually target a net total return (once fully invested) of 7% or more.

Attraction

Assets such as solar and wind provide certain contracted revenue flows affording closed-end funds the ability to pay regular targeted dividend payments to investors. At a time of historic low interest rates, such vehicles are attractive to a range of institutional investors including pension funds, insurance companies, sovereign funds and wealth managers as well as retail investors.

The asset class has also benefited from an increased focus on responsible and sustainable investing against a background of increased awareness of environmental issues and changes in government policy, not least resulting from the recent change in the US administration.

The London Stock Exchange is home to over 450 listed investment funds, which in aggregate, represent more than $200 billion in market capitalization. It is considered to be the world's leading market destination for listing funds.

The market provides a platform for a wide range of investment funds and strategies to access pools of capital from both institutional and retail investors and has been at the forefront of admitting funds investing in alternative asset classes such as renewable energy infrastructure and private equity.

Initially, many of these funds targeted European assets. Interest from managers of US-based (as well as other international) assets has been growing.

London provides managers with a number of potential comparative advantages over other listing venues, including a well-established and knowledgeable investor base with a large pool of investable capital and a strong understanding of the fund market, key asset classes and investment strategies.

The market allows an efficient mechanism from a both a cost and logistical perspective for growing a fund through further equity issuances, including placing or share issuance programs. This allows funds to expand and broaden their investments as their strategies evolve and as they build an investment track record.

In the secondary market, London affords multiple trading channels offering intra-day liquidity for funds.

It has a well-developed network of experienced advisers, including banks and brokers, law firms, accounting firms and fund administrators that provide the necessary support for initial public offerings and during the life of the fund, as well as access to a wide base of experienced independent directors for fund boards.

The market for new fund listings has not been materially affected by the global pandemic, and there was significant activity in the fourth quarter of 2020 and in the first month of the new year. Investor IPO roadshows have been run effectively on an entirely virtual basis.

Structure

London-listed closed-end funds are typically structured as UK investment trust companies or Channel Island companies (Guernsey in particular).

Such funds may invest into US assets through the establishment of a US holding company designed to mitigate tax leakage between the UK and the US.

A listing will typically be sought on the "Main Market" in London, either through a premium listing or a listing on the "Specialist Fund Segment," which has more flexible eligibility criteria for a closed-end fund and less onerous post-listing continuing obligations. A premium listing means the listing is, in broad terms, subject to the highest listing standards and more extensive continuing obligations. Fund listings by renewables fund managers are less common on the AIM market.

For a premium listing, a closed-end fund will need to satisfy certain asset diversification requirements to ensure that there is prudent risk spreading within its portfolio. As with other fund listing venues, including New York, the usual historical financial track record requirements for new applicants will not apply to newly established funds. The London market also allows the listing of special-purpose acquisition companies (SPACs), a structure familiar in the United States.

Typically, a closed-end fund whose objective is to invest in renewable infrastructure will hold its investments in projects through special-purpose vehicles that are ring-fenced from other investments to mitigate portfolio cross-contagion.

Funds acquiring US assets often seek to introduce bank leverage and tax equity into the investment structure, usually with the fund having a controlling equity stake. However, such funds can enable minority investments to be taken, including through a range of joint venture and co-investment arrangements with third parties.

Funds target assets at the different stages of development, although given the objective of providing regular income returns to investors, funds targeting projects that are already operational or operational in the near term will have certain advantages over portfolios comprising development- and construction-phase projects where contractual income through offtake agreements will be delayed and where the fund may bear some development or construction risk (although these will often by mitigated through development or construction contracts).

Closed-end listed funds usually issue a single class of ordinary share with full voting rights and have a separate board independent of the investment manager. The strength of the board, and the corporate governance arrangements more generally, are becoming increasingly important within the institutional investor community.

Some fund managers are raising capital in the London market to buy US renewable energy assets.

The investment manager will have an investment management agreement in place with the fund and will usually be afforded a high degree of investment discretion within the parameters of the fund's investment policies and restrictions. Management agreements will often be terminable on between six and 12 months' notice, usually after an initial post IPO fixed period of, typically, between two and four years or so. Management fees on these funds vary, but are often between 0.5 and 1% of net asset value. Some funds also include an additional performance-based fee based on investment outperformance of hurdle returns.

The total costs of a London IPO for a closed-end company (including commissions on sales of shares) are usually limited to 2% of the initial fund net asset value.

Brexit

The impact of the UK leaving the European Union at the beginning of this year does not seem to have diminished investor interest in these types of vehicles, although accessing non-UK European investors remains a little complicated given the requirement to comply with a range of local private placement regimes.

These types of closed-end fund may also be of interest to US and other international investors, although navigating regulatory requirements, securities law and differing tax considerations is not without some challenges. ◎

Pension Investments Bring New Opportunities and Some Challenges

by Marjorie Glover in New York, and Keith Martin in Washington

Care must be taken in cases where pension funds invest directly in US renewable energy projects to avoid turning the projects into "plan assets."

If the projects turn into "plan assets", then burdensome legal obligations administered by the US Department of Labor will come into play.

US pension funds control more than $32 trillion in assets.

Norman Anderson, chairman and CEO of CG/LA Infrastructure, wrote in Forbes in late December that they could be "utterly transformative" for US infrastructure if even only a small fraction of the amount they have to invest were put into the sector.

Pension plans have invested in US infrastructure for many years by investing in private equity funds that invest, in turn, in projects or project developers. Some larger pension plans have been more likely lately to invest in projects directly.

The climate initiatives being launched by the Biden administration and the eagerness of pension fund and other institutional investors to invest in ESG assets may accelerate this trend.

Plan Asset Consequences

US pension plans are subject to strict regulation by the US government. This regulation poses traps for the unwary and imposes constraints on how projects with equity from pension funds are structured.

Non-US pension funds are not subject to the same constraints.

The US Employee Retirement Income Security Act of 1974 — ERISA, for short — treats any assets in which a US pension plan takes an equity interest potentially as "plan assets" unless an exemption applies.

If a project company, tax equity partnership or project becomes a plan asset, then strict ERISA requirements apply, including the need to comply with pension fiduciary duties, restrictions on certain transactions between related parties, fee disclosure, other reporting and disclosure, bonding and limits on fees paid to managers. In certain cases, significant penalties may be imposed and, in rare cases, the US Department of Labor may step in to unwind the transaction or investment.

Most renewable energy projects are owned through tiers of entities.

At the bottom of the ownership chain is a special-purpose limited liability company that owns the project. This project company is usually "disregarded" — or ignored — for federal income tax purposes. Another limited liability company usually sits immediately above the project company. It is usually treated as a partnership for tax purposes and may have two or more owners. The project developer or "sponsor" is one. The other may be a tax equity investor. A pension plan might invest in an upper-tier partnership with the sponsor and then that upper-tier partnership owns the sponsor interest in the tax equity partnership.

ERISA applies a "look-through" test to determine whether each entity in the structure includes plan assets subject to ERISA.

If benefit plan investors hold at least 25% of any class of equity in any entity down the ownership chain, then the assets of that tier entity are deemed to be plan assets and the ERISA rules will apply, unless another exemption applies.

If an upper-tier entity — for example, the upper-tier partnership between the developer and benefit plan — is deemed to hold plan assets under the 25% test, then the proportionate share of investment held by the benefit plan in the next lower entity is tested to determine whether the investment by the benefit plan is at least 25% in that next tier down. This is tested by multiplying the percentage interest of the benefit plan in the upper-tier partnership by the percentage interest of the upper-tier partnership in the tax equity partnership. If the interest of the benefit plan in the tax equity partnership is less than 25%, then there is no need to keep testing down the ownership chain.

If the project is a plan asset, then the ERISA restrictions on transactions with affiliates, fiduciary responsibilities, duty to disclose fees and other obligations could fall on all three entities in the ownership chain.

The project company might have a harder time entering into contracts with affiliates of the sponsor.

The key to avoid having the project turn into a plan asset and, therefore, to avoid any of these issues is to structure the transaction with the pension plan so that it fits into one of three exemptions: the 25% benefit plan investor exemption, a venture capital operating company exemption or a real estate operation company exemption. The last two are called the VCOC and REOC exemptions. There are other exemptions, but these are the most commonly used.

Care must be taken when pension funds invest directly to avoid turning projects into "plan assets."

25% Benefit Plan Investor

The first exemption applies if the investment by pension plan investors is limited to less than 25% of each class of equity interest in the entity being tested. If benefit plan investors hold less than 25% of every class of equity in the entity, then the entity will not be considered to hold plan assets subject to ERISA.

For purposes of calculating the 25% limit, any equity interests held by government pension plans, church plans and non-US pensions are excluded from the numerator but are included in the denominator. As a result, this exemption works well where one or more non-US pension plans and US public pension plans, such as CalPERs, invest alongside a private pension plan.

The 25% limit must be re-measured each time someone acquires a new interest or increases its interest in the entity.

In addition, when calculating the 25% limit, interests held by the project developer and its affiliates must generally be excluded from both the numerator and denominator of the test.

Going back to application of the 25% test, if a benefit plan investor owns at least 25% of the upper-tier partnership with the developer, then the benefit plan investor has a large enough interest in the upper-tier partnership potentially to bring ERISA into play. The 25% test would then be applied to the tax equity partnership that is the next tier down. If the benefit plan investor owns at least 25% of any class of equity in it, then the tax equity partnership will also be a plan asset. For purposes of the 25% test, the benefit plan investor is treated as owning its percentage interest in the upper-tier partnership times that partnership's percentage interest in the tax equity partnership. For example, assume the upper-tier partnership is owned 32% by the benefit plan and is not otherwise exempted under ERISA. Assume the upper-tier partnership holds 50% of a class of equity in the tax equity partnership and all other interests are owned by non-benefit plan investors. In this case, neither the tax equity partnership nor the project below it would be considered a plan asset, since only 16% of the tax equity partnership is considered owned by the benefit plan.

However, a tax equity partnership usually has a class B interest that is held entirely by the sponsor and a class A interest that is held by the tax equity investor. Thus, the upper-tier partnership between the sponsor and benefit plan is likely to own 100% of a class of equity interest: the class B interest.

Anyone relying on the 25% exemption should monitor the 25% limit on an ongoing basis, calculate the limit properly and consider the impact of investor defaults, interest transfers and restructuring into alternate vehicles.

VCOC Exemption

The second exemption is the VCOC exemption. This exemption is often used when investment by private US pension funds exceeds or is at risk of exceeding the 25% limit. To qualify for the VCOC exemption, the fund must meet both an asset test and a management rights test.

The focus of the VCOC exemption is the entity in which the pension plan invests — in this case, the upper-tier partnership with the developer that holds the sponsor interest in the tax equity partnership.

To fit in the exemption, that entity must hold at least 50% of its assets valued at cost in operating companies. For this purpose, operating companies are companies that are, directly or through majority-owned subsidiaries, actively engaged in the production of goods or services.

It is not clear whether ownership of a project through the sponsor side of a tax equity partnership would be considered ownership of the project through a majority-owned subsidiary, since the sponsor starts with only a 1% interest in partnership income and losses that increases later to 95%, but it often has a majority share of the cash and day-to-day control over the business from inception.

If a benefit plan investor entity will make multiple investments, then the 50% test must be met when the first long-term investment is made. If the entity does not meet the 50% test on the date of its first long-term investment, then it will not qualify as a VCOC.

Most US pension plans investing in US renewable energy projects invest through a blocker corporation to avoid preventing the project from qualifying for an */ continued page 56*

Pension Investments

continued from page 55

investment tax credit and accelerated depreciation. These tax benefits cannot be claimed on such a project owned partly by a government or tax-exempt entity. The tax benefits are disallowed to the extent of the tax-exempt ownership.

Use of a blocker corporation by itself does not solve the problem if government or tax-exempt entities in the United States own 50% or more of the blocker by value, as that will turn the blocker into a "tax-exempt controlled entity" with the same result. The benefit plan investor entity would have to elect out of "tax-exempt controlled entity" status, which it may be unwilling to do, because the election out requires reporting dividends and capital gains upon exit as "unrelated business taxable income" on which any non-government pension plan would have to pay income taxes.

In cases where a blocker is used, the tests are applied at the blocker level if the blocker has multiple US private pension plans as owners. (Public plans and foreign plans are included in the denominator but not the numerator.) An example is where several pension plans invest through a jointly owned blocker. The 25% test is applied first at that level and, if it is a problem, then the blocker must be a VCOC (or qualify for another exemption).

The other VCOC test is a management rights test. To qualify for the VCOC exemption, the pension plan must obtain direct contractual management rights in the underlying qualifying operating company and must actually exercise those rights in the ordinary course with respect to at least one qualifying operating company each year.

In the case of a jointly owned blocker corporation plus three tiers of entities, these contractual rights would have to run between the blocker corporation and project company. The entity seeking to have VCOC status would have to have direct contractual rights in an operating company and generally cannot have these rights through intermediate entities unless the entity seeking to have VCOC status owns a majority interest in the intermediate entity and each underlying subsidiary.

A problem exists if the interest in the project company is held by an intermediate entity that holds a minority interest in the project company. In that case, the project company generally would not be a valid VCOC investment. This problem may be solved by having the entity seeking VCOC status own 100% of the intermediate holding company.

Thus, the management rights must be direct contractual rights between the benefit plan investor entity and the operating company giving the benefit plan investor entity the ability to influence or have a substantial say in management of the operating company.

The right to appoint an operating company board member with full voting rights is generally sufficient for this purpose.

In addition, the US Department of Labor has advised that the following rights will be considered sufficient management rights for purposes of the VCOC test: the right to meet periodically with management, appoint company officers, appoint board or management observers, advise and consult regarding the conduct of business, examine the operating company's books and records and receive periodic operating company financial statements.

The benefit plan investor entity need only possess some of the rights. It is not necessary to have all of them, although in practice, the benefit plan investor entities typically request management rights side letters that include each of the rights.

To qualify for VCOC status, the benefit plan investor entity must have its own direct contractual rights. For this purpose, rights shared with other investors or co-investors will not qualify. Rights set out in the operating company agreement generally will not qualify unless the rights are specifically designated as rights of the particular benefit plan investor entity.

As a result, entities seeking to establish or maintain VCOC status typically ask each portfolio company to enter into a separate "management rights side letter" conferring direct management rights upon the blocker corporation. The management rights side letter usually includes the list of management rights listed earlier.

REOC Exemption

The third exemption is the REOC exemption. This exemption is more common to find used in real estate investments.

It is similar to the VCOC exemption, except that the nature of the investments is different. To qualify as a real estate investment, the REOC must have rights to participate directly in the management or development of the underlying real estate, and must actually exercise the management rights in at least one investment each year.

Since the real estate investment must be actively managed, fallow land and triple-net-lease assets typically do not qualify as REOC investments.

There is not a lot of guidance about whether specific infrastructure investments, such as power plants, are considered real estate for purposes of the REOC exemption. ◎

Environmental Update

As President Biden's appointees take their places and his nominees move through the Senate approval process, here is how the roster of key players on federal environmental and climate policy has shaped up:

Agency Heads

Biden nominated the secretary of the North Carolina Department of Environmental Quality, Michael Regan, to head the US Environmental Protection Agency.

Regan was an air-quality specialist who had served at EPA under both Presidents Clinton and George W. Bush. He later worked for the Environmental Defense Fund before being asked to lead North Carolina's main environmental agency in 2017.

If confirmed, Mr. Regan will be the first Black man to lead the agency at a time when the Biden administration is expected to push for environmental justice.

Janet McCabe, who served as the acting assistant administrator for the office of air and radiation at EPA for much of the Obama administration, has been nominated for deputy administrator. While leading EPA's air office, McCabe helped develop EPA's now defunct Clean Power Plan.

President Biden nominated US Representative Deb Haaland (D-New Mexico) to be the new Secretary of the Interior. While she had served on the House's Natural Resources Committee, Haaland was first elected to Congress in 2018. Before that, she was the chair of the Democratic party in New Mexico and oversaw business operations for a large tribal gaming enterprise.

During the presidential campaign, Biden promised to "transition away from the oil industry," which he said will involve restricting new oil and gas permits on public lands that are overseen by Interior. Haaland would be at the head of Mr. Biden's efforts to protect some of the 500 million acres of federal land that the Trump administration opened to construction, mining and logging activities.

Haaland is one of the few Native Americans elected to Congress and would be the first to head the US Department of the Interior. With both the Bureau of Indian Affairs and the Bureau of Indian Education falling within the agency, Interior also provides services to 1.9 million Native Americans and maintains the government's relationship with more than 500 federally recognized tribes.

White House Trio

Biden chose Brenda Mallory to chair the White House Council on Environmental Quality, the group that Biden will use to try to shape and harmonize environmental policy across the new administration.

CEQ also oversees the implementation of the National Environmental Policy Act, or NEPA, which requires federal agencies to use environmental assessments and impact statements when making decisions related to any major development or infrastructure project that requires federal approvals.

Mallory served as the general counsel to the Council on Environmental Quality under Obama. Before that, she served in various roles at EPA over a 15-year tenure, including as the agency's principal deputy general counsel. She resigned her position as director of regulatory policy at the Southern Environmental Law Center to accept the new position.

Former EPA Administrator Gina McCarthy will lead the White House Office of Domestic Climate Policy, a new high-level position with a key role in coordinating and driving climate policy across federal agencies.

McCarthy headed up EPA under the Obama administration and more recently led the Natural Resources Defense Council.

As climate coordinator on the domestic front, McCarthy will advise the president and work with cabinet and other senior figures to coordinate work across EPA, Interior, the US Department of Energy and other federal agencies. She will also lead a push for legislative options for reducing greenhouse gas emissions and climate mitigation.

In a statement to the press, McCarthy said that tackling the climate crisis "is all about using the entire federal budget and the strength of the entire cabinet" to address climate concerns.

In addition to the new domestic coordination role that McCarthy will plan, Biden also created the new position of "presidential envoy on climate" to lead efforts "to combat the climate crisis and mobilize action" with emphasis on foreign coordination on climate issues. Biden tapped former US Secretary of State and US Senator John Kerry. The new presidential envoy on climate will be a member of the National Security Council.

Early Action

One early sea change from Trump to Biden will be in the area of environmental enforcement, with the new administration having already taken steps to remove barriers and ramp up environmental enforcement of federal / *continued page 58*

Environmental Update

continued from page 57

environmental laws and regulations.

The nominee for EPA administrator, Michael Regan, is expected to follow his playbook in North Carolina by increasing inspections and penalties levied, at least compared to the level of enforcement activity under Trump.

EPA and the Department of Justice are expected to make environmental justice a central concern when bringing and settling enforcement actions and making agency decisions in rulemakings.

In his first executive order on climate change, Biden directed EPA and the Department of Justice to focus on environmental justice in their enforcement actions. A January 27 executive order on "Tackling the Climate Crisis at Home and Abroad" says that it is the Biden administration's policy "to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and underinvestment in housing, transportation, water and wastewater infrastructure, and health care."

EPA and the Department of Energy describe environmental justice as follows:

> "the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies . . . . Fair treatment means that no population bears a disproportionate share of negative environmental consequences resulting from industrial, municipal, and commercial operations or from the execution of federal, state, and local laws; regulations; and policies."

A number of top EPA regulators selected by Biden have broad experience with environmental justice issues, including the new nominee for EPA administrator. Biden also plans to create a White House Environmental Justice Interagency Council and a White House Environmental Justice Advisory Council to prioritize equity issues in all agencies.

A number of Trump-era limits on enforcement have already been scrapped.

DOJ rescinded nine environmental policy memoranda put in place under the prior administration, citing the need to give it a full range of enforcement discretion and arguing that the policies conflicted with President Biden's executive order on protecting the environment.

Notable rescissions include the withdrawal of a recent memo limiting enforcement discretion and the repeal of a prohibition on using supplemental environmental projects, referred to as SEPs, in settlement agreements to resolve enforcement actions.

SEPs are environmentally beneficial projects funded by settling defendants in enforcement actions where the defendants agree to take actions that are usually beyond what a court could order based on the original violations to resolve the complaint. Pre-Trump, SEPs were commonly used to bring the regulated community into voluntary settlements by allowing defendants to offset civil penalties while fostering community goodwill. After withdrawal of the SEP ban, environmental groups moved to drop lawsuits challenging the ban.

The new administration also appears to have signaled a retreat from the prior administration's opposition to citizen enforcement actions, at least under the Clean Air Act. DOJ recently decided not to appeal a settlement between a utility and the Sierra Club over alleged violations of the Clean Air Act's new source review permitting program. The Trump administration had opposed the settlement.

Biden also moved to bolster the role of science in EPA and other agencies' policies. A presidential memorandum directed agencies to "make evidence-based decisions guided by the best available science and data," and a separate executive order re-established the Council of Advisors on Science and Technology, or PCAST. PCAST will advise the president on policy affecting science, technology and innovation, and on how science can inform policy decisions on a range of issues.

Climate

On climate, Biden's initial executive orders have formalized a "whole-of-government" approach to addressing climate change. They direct the government to take multiple steps to tackle the issue, both domestically and abroad. They also make climate change a national security priority by directing the integration of climate into national security decisions.

The orders seek to "leverage the federal government's footprint" by directing agencies to take various actions, such as procuring low-carbon goods and services, developing resiliency plans to offset climate impacts, eliminate fossil fuel subsidies if "consistent with applicable law," and limit new oil and gas leasing on federal lands "to the extent possible," subject to an exception for tribal lands.

The orders further set out the process by which the administration intends to create national greenhouse gas emissions targets under the Paris climate accord.

President Biden signed an executive order to have the US rejoin the Paris climate agreement as one of his first acts on inauguration day. The US officially withdrew from the accord late last year, after President Trump began the process in 2017. The US was the only country of the nearly 200 signatories to have withdrawn.

The 2015 agreement aims to avoid or limit the most significant climate change projections by keeping average global temperatures from rising by more than 2 degrees Celsius compared to pre-industrial times, with a preferred goal of less than 1.5 degrees Celsius by 2100. Global temperatures have already increased by a little more than one degree Celsius. The parties to the Paris accord were originally set to meet in Glasgow, Scotland in November 2020 to consider strengthening their emissions reduction targets, but the meeting was postponed for a year due to COVID-19.

Biden's new climate orders direct federal agencies to ensure that every federal infrastructure investment "reduces climate pollution" while taking steps to accelerate clean energy and cleaner transmission projects.

As a candidate, Biden pledged to make significant reductions in greenhouse gas emissions from the US electricity sector, to drive the nation's power grid toward net-zero carbon dioxide emissions by 2035 and to make the country carbon-neutral by 2050.

Carbon emissions from the electricity sector have been falling as utilities add renewable energy sources like wind and solar and as coal-burning plants continue to be retired, but the reductions are not enough to meet Paris targets for the US.

Biden will need Congressional help to advance his climate agenda. Senate Energy Committee Chairman Joe Manchin (D-West Virginia) will play an outsized role and as a moderate voice that will have to be brought along. Manchin called on Biden to commit to the production of natural gas for manufacturing and other domestic uses as part of a broader climate-change strategy.

In 2017, transportation overtook electricity generation as the largest source of greenhouse gas emissions in the US. Biden is expected to strengthen automobile emissions standards, but rulemaking in the area will take time.

In the meantime, expect the administration to try to make deals to reduce emissions from cars and trucks. Newly minted national climate adviser Gina McCarthy recently told the press that "we are having conversations with the car companies" as part of the administration's broader effort to require greenhouse gas emission cuts from the transportation sector. Currently, those discussions appear to be on a company-by-company basis.

Biden is expected to address a joint session of Congress on February 23 in part to roll out more specifics to of his "build-back-better" agenda. Announcements related to federal investment in electronic vehicles and the required infrastructure for EVs are anticipated.

Clean Power

A federal court struck down one of the Trump administration's key efforts to roll back climate regulation on January 19.

The court vacated and sent a Trump "affordable clean energy rule" — called ACE — back to EPA, allowing the incoming Biden administration to start from a blank slate for regulating emissions from the power sector. The expectation is that Biden will try to impose tougher limits on carbon dioxide pollution from power plants.

The court also vacated a separate EPA action extending compliance timelines for all rules issued under section 111(d) of the Clean Air Act, and it rejected a challenge to EPA's underlying authority to regulate greenhouse gas emissions from power plants.

A split three-judge appeals court panel held that the "central operative terms" of the ACE rule "hinged on a fundamental misconstruction" of the Clean Air Act.

The ACE rule focused solely on actions that can be taken on the particular power plant site to limit emissions without going beyond the fence line. The court said this is too narrow a construction of federal authority in this area.

It also said the extended compliance timeline in the ACE rule was "arbitrary and capricious."

The one dissenting appeals court judge would also have struck down the ACE rule, but based on his view that EPA has no authority at all to regulate power plants under section 111 of the Clean Air Act — the authority that EPA cited for the ACE rule — because EPA already regulates hazardous air pollutant emissions from power plants under Section 112.

EPA adopted the ACE rule as a replacement for the Obama Clean Power Plan that tried to reduce greenhouse gas emissions across the power sector. The Clean Power Plan had its own problems. The US Supreme Court blocked implementation and EPA replaced it with the ACE rule after Trump took office.

Power companies may be feeling whiplash. The Biden administration is likely to use the ruling to justify replacing the ACE rule with something closer to the sector-wide regulatory approach taken in the Clean Power Plan. */ continued page 60*

Enviornmental Update

continued from page 59

The administration is now effectively required to start over again. The rulemaking process required to draft a new EPA rule for power plant emissions will take time even if EPA has a template in mind.

A company or industry that supported the ACE rule in the litigation could ask the full US appeals court en banc or the US Supreme Court to review the decision to vacate the ACE rule and send it back to EPA, but the Biden administration will certainly not appeal. The Supreme Court never ruled on the merits of the Obama Clean Power Plan before Trump took office. It merely enjoined enforcement.

The case involving the ACE rule is *American Lung Association v. EPA*.

Migratory Birds

The US Fish and Wildlife Service finalized a rule on January 7, before Trump left office, that would limit when companies can be prosecuted for killing protected birds under the Migratory Bird Treaty Act of 1918, or MBTA, but the new rule is already in doubt.

The rule would restrict prosecution under the MBTA to intentional killings only.

Thus, an "incidental take" of a protected species will no longer trigger potential prosecution as long as the rule stands. Incidental taking of birds can occur from such things as power lines and wind turbine strikes or oil spills or ponds containing hazardous materials.

The final rule says that "[l]imiting the range of actions prohibited by the MBTA to those that are directed at migratory birds will focus prosecutions on activities like hunting and trapping and exclude more attenuated conduct, such as lawful commercial activity, that unintentionally and indirectly results in the death of migratory birds."

The US Department of the Interior had previously issued a policy memorandum promising not to prosecute companies or individuals who inadvertently harm protected birds and limiting prosecution to activities specifically meant to hurt or kill them. However, a federal judge overturned it in August 2020, calling Interior's legal reasoning "unpersuasive."

The new rule codifies the now-withdrawn 2017 memo.

The entry of the Biden administration has put the fate of the new rule in doubt. The US Fish and Wildlife Service froze the rule and formally reopened public comment on migratory bird protections. The new rule will now not take effect before March 8, 2021 at the earliest.

The Trump administration had asked a US appeals court to reinstate the 2017 policy memorandum, but the US government has now asked the appeals court to put that appeal "in abeyance."

The incoming Interior secretary, Rep. Deb Haaland (D-New Mexico) sponsored a bill while in Congress that would reverse the Trump administration's reinterpretation of the MBTA.

More than 1,000 species are protected by the MBTA.

— contributed by Andrew Skroback in New York

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