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Disappearing Tax Equity

Tax equity is emerging as a potential major choke point for the US renewable energy market. Many developers are having difficulty finding it this year. Without it, some projects that would have been built this year will be delayed. Large bank loan loss provisions and tax credit carryforwards are making it tough for banks, which are the dominant tax equity investors, to forecast tax capacity not only for this year, but also for 2021.

Tax equity investors from five banks talked during a conference call in late July about the condition of the US tax equity market. The investors are Robert Capps, managing director for tax equity origination for SunTrust, Eric Cohen, group head of renewable energy finance for Fifth Third Bank, Eric Heintz, director of energy financing for M&T Bank, Scott McClain, executive vice president and head of equipment finance for First Horizon Bank, and Yonette Chung McLean, a managing director on the tax equity desk at RBC Capital Markets. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Still Doing Deals?

MR. MARTIN: This is the third in a series of calls since late March on the condition of the tax equity market. One problem with these calls has been the impression given that it is largely business as usual for tax equity this year, when clearly it is not. Many developers are having trouble this year raising tax equity.

We start this call with someone who is currently out of the market. Robert Capps from SunTrust, what is the story there? / continued page 2

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NEW CORPORATE PPAs have become scarce.

Brokers and lawyers report less interest among US companies in signing long-term corporate power purchase agreements due to uncertainty about the economy.

An interesting question is what happens to existing PPAs with corporations in the retail trade that are having to close stores.

The US Energy Information Administration is projecting that commercial-sector electricity demand will be down 7.4% in 2020 compared to 2019. The agency expects overall US electricity usage to be down 3.6%. The latest forecasts are in the "August 2020 Short-Term Outlook."

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MR. CAPPS: SunTrust and BB&T merged late in 2019. In early Q2, when we began formulating a forecast for the combined company and adding in the COVID impact on the economy, that led to a fairly conservative forecast of what our tax capacity might be going forward.

We also had to take into account some one-time expenses of the merger and the current very low interest rate environment. When we put those two dampening effects on tax capacity into our model, we ended up projecting significant tax credit carryforwards.

Such carryforwards are fine economically, but they were adversely affecting our CCAR, or bank stress case test, which is a problem for any bank. When we combine that with the fact that we had very strong deal origination at the end of 2019 and into early 2020, leading to a fairly large increase in full-year 2020 volume over 2019, we came to the reasonable conclusion that it probably made sense to take a pause until we can get a little more clarity around COVID.

MR. MARTIN: Do you have any indication yet what 2021 tax capacity will be?

MR. CAPPS: We do not. I think we need a little more of COVID in our rear-view mirror instead of our windshield before we will have a better sense of what it will be. We will probably take another shot at a forecast in late Q3.

MR. MARTIN: Is anyone else currently out of the market?

MR. MCCLAIN: First Horizon is finished taking new opportunities for the remainder of this year basically for the same reasons that Robert mentioned — the impact of COVID, as well as the merger between Iberiabank and First Horizon Bank that closed on July 1. Until we have a better feel for our tax position, we are focused on filling out 2021 and, at this point, we are getting close to all the 2021 deals to which we are prepared to commit at this time.

MR. MARTIN: What about others? Fifth Third?

MR. COHEN: Our goal is to remain in the market this year and to look for opportunities for both 2020 and 2021. We do not have a fully formed view yet from a solar or bank perspective about how much tax capacity we have to use next year.

MR. MARTIN: Eric Heintz, is M&T Bank still in the market?

MR. HEINTZ: We are in the market, but are slowing down. We hope to do one more 2020 deal and are likely to commit to a 2021 opportunity in short order, but we will be relatively quiet thereafter until we have more certainty about potential outcomes in the economy and public policy.

One of the big questions for banks is how much of our loan loss provisions will ultimately be realized in charge-offs. This makes forecasting our tax capacity in 2021 and 2022 particularly difficult.

MR. MARTIN: Yonette Chung McLean, what about RBC Capital Markets? Are you in the market?

MS. MCLEAN: Yes. For some context, RBC is a syndicator of tax credits. Our investor clients tend to be regional and super-regional banks, insurance companies and corporate investors. We have seen a couple investors pull back, but most of our investors continue to look at deals.

We will write tax equity checks for a couple more deals in 2020, but our focus is largely on 2021 at this point. There is a fair amount of activity within our platform.

MR. MARTIN: For those of you still in the market, let's drill down into what that means. Eric Heintz, you said you will do one more 2020 deal. Have you already signed the term sheet for it?

MR. HEINTZ: No, but we expect to do so in the next couple weeks after we reach agreement on pricing.

MR. MARTIN: Eric Cohen, you said the goal at Fifth Third is to look for more 2020 and 2021 deals, but you do not have a fully formed view yet about your tax capacity. What does that mean in terms of what you are actually doing?

Tax equity is emerging as a major potential choke point for the US renewable energy market.

MR. COHEN: To clarify, we do not yet have a fully formed forecast of 2021 tax capacity. We know what we have left for 2020. We have a decent amount of 2020 tax capacity. We are looking to use it on strategic opportunities.

That starts with existing clients with whom we already have a relationship and know can execute. We have been a lender to this market for the last eight years and a tax equity investor for the last 18 to 24 months. Tax equity is a newer product for us.

We have a strategic mindset. We are looking to use that tax capacity to reward clients of either our advisory team on the investment banking side or the lending team, or both. We feel like there is enough opportunity to fill our dance card with such companies or with companies with whom we have been talking for a while and want to get something going.

MR. MARTIN: You do only sale-leasebacks at this time, correct?

MR. COHEN: That is correct. We are evaluating a partnership flip product for 2021. Obviously a lot of that depends on what we think the market looks like for 2021. We would like to be able to offer both.

MR. MARTIN: Yonette Chung McLean, you said you are still signing new commitments for deals that will close this year.

MS. MCLEAN: Yes, we have capacity for two more deals this year. We are in term-sheet discussions. Our thought is to have those deals closed no later than mid-October.

MR. MARTIN: Give me a sense of whether this is a normal pattern for those of you who are still doing deals. Yonette, you said two more deals this year. Is that typical for a year at this stage?

MS. MCLEAN: No. We have tended in the past to see a few deals that pop up at the end of the year. They might get done if our investor-partners find that they have additional tax capacity after filing their tax returns in the summer.

We are seeing a fair amount of abnormality this year in the number of deal submissions. While the number of deals we do has been growing year over year, the challenge this year is processing the number of deals being sent to us every day. It feels like trying to drink out of a fire hose.

MR. MARTIN: To what do your attribute the increase in volume?

MS. MCLEAN: Developers are finding many doors closed as investors scramble to understand what effect COVID will have on tax capacity. There is a crush to get into any door that remains open. / continued page 4

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A US DEPARTMENT OF ENERGY request for information to help it implement the Trump bulk-power system order identifies six foreign adversaries against which the order is directed.

It also hints, through the questions it asks, at what might soon become best practices in the power industry.

The order imposed an immediate ban as of May 1, 2020 on the purchase, use or transfer of as-yet unidentified foreign adversary equipment that might be used to harm the US power grid. (For more detail, see "Trump bulk power system order: Market reaction" in the June 2020 *NewsWire*.)

The Department of Energy said in July that the six foreign adversary countries whose equipment is suspect are China, Russia, North Korea, Iran, Cuba and Venezuela and that two of the countries – China and Russia — already have the ability to shut down US pipelines and the electricity grid.

The department asked for information about the following types of equipment: transformers, reactors, capacitors, circuit breakers and "generation (including power generation that is provided to the [bulk power system] at the transmission level and back-up generation that supports substations." It said the transformers on which it is focused have a low-side voltage of 69 kilovolts or higher.

It suggested that utilities can use a model on the DOE website to assess their supply-chain vulnerability to cybersecurity threats. The model can be found at the following link: https://www.energy.gov/ceser/activities/cybersecurity-critical-energy-infrastructure/energy-sector-cybersecurity-0

The department had previously said that the request for information would be used to collect input to help inform a later process to vet suppliers' equipment.

One question coming up in deals is whether equipment at projects that connect to distribution lines rather than the transmission grid are potentially affected by / continued page 5

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Outlook for 2021

MR. MARTIN: So SunTrust is out of the market this year. First Horizon is not making any new investments. M&T is slowing down; it will do one more 2020 deal. RBC has capacity for two more deals. Fifth Third has tax capacity, but is reserving it for existing clients.

This does not sound like a very promising market for developers who are looking for tax equity. It explains some of the desperation developers are feeling.

Let me move to 2021. Some of you have already addressed this, but what is your sense currently about what 2021 will look like? Developers report that it is hard not only to secure 2020 tax equity commitments, but also that banks are reluctant to commit to 2021 deals because of uncertainty about the future direction of the economy. Eric Cohen, true or false?

MR. COHEN: True. Robert Capps did a nice job summing it up. We really do not know yet what loan losses will look like, and that will drive taxable income.

MR. MARTIN: Eric Heintz, same story for 2021?

MR. HEINTZ: Yes. Hopefully it will begin to improve as we move into the fourth quarter of this year and first quarter of next year, but actual charge-offs are hard to predict at this time. That applies to 2022 as well.

MR. MARTIN: The four biggest banks — JP Morgan, Wells Fargo, Bank of America and Citigroup – reported aggregate loan loss provisions of $33 billion as of the end of the second quarter.

Yonette Chung McLean, in a normal year would you already be writing commitments for the next year?

MS. MCLEAN: Yes. In fact, we are currently in close mode on a transaction that will fund in 2021. We closed a couple deals earlier this year as well that will fund in 2021.

The difference between my panel colleagues and our investors is we have banks, insurance companies and corporates. While the banks, RBC included, have some constraints, it is not exactly the same for insurance companies and corporates.

There are corporates that are doing well in the current economy and have the ability to do business not only this year, but also for 2021.

We are still doing 2021 deals. The only difference is we see investors being a little more selective in picking deals.

Overall 2020 Volume

MR. MARTIN: The tax equity market was roughly a $12 to $13 billion market last year for renewable energy. Many people expected it to hit $15 billion this year. Does that now seem unlikely? Robert Capps.

MR. CAPPS: Although we are out of the market, as I said earlier, we have had a record year in 2020 commitments. My sense is the market will still get to roughly $15 billion, even with the headwinds that it is facing.

Going back to your last question to Yonette about 2021, we made some 2021 commitments and closed already on those transactions. We will be funding 2021 deals. We are just taking a pause on new 2021 commitments.

MR. MARTIN: What about the rest of you? How does this year feel in terms of aggregate volume? Eric Cohen.

MR. COHEN: I don't think I have the best gauge on that as a relatively new entrant.

MR. MARTIN: Let me ask it in a different manner. What percentage of renewable energy deal volume do you expect to have done by the end of this year as compared to last year?

MR. CAPPS: A 200% increase.

MR. MARTIN: Eric Cohen?

MR. COHEN: We had a huge increase this year as we ramped up that product.

MR. MARTIN: Eric Heintz?

MR. HEINTZ: We will be pretty consistent in volume this year over last year.

MR. MARTIN: Scott McClain, how will your volume this year compare to last year?

MR. MCCLAIN: Last year, we did not execute any tax equity transactions due to a different merger. That is a long story, but our tax position was not advantageous last year. So our year-over-year increase is basically infinite. We will do a significant amount of tax equity investment, whereas last year we did a lot of debt financings. Our overall volume will be the same, but it will be shifting to tax equity from debt.

MR. MARTIN: I think two of you — Fifth Third and First Horizon — are doing only sale-leasebacks at the moment. Fifth Third is seeking permission to do partnership flips. Is First Horizon also looking for that permission?

MR. MCCLAIN: Not yet. It is something that I looked at previously at a predecessor organization, and coming to Iberiabank, we just did not have the tax base to justify the product. Now that we have merged, the bank has gone from $32 billion to $83 billion in assets. Taking COVID out of the picture, I would probably be looking to offer that product. With COVID and all the uncertainty around it, I don't know when will be the right time to introduce it. It is in our minds as a future offering.

MR. MARTIN: Yonette, how does volume this year compare to last year?

MS. MCLEAN: About double.

MR. COHEN: One thing to add is we may end up taking on deals for 2021 that generate tax benefits that can be carried back into 2020 if it looks in the second half of 2020 like we will end up with additional 2020 tax capacity.

If things are better in 2020 than expected or meet current forecasts, we may pick up some incremental capacity in 2021 even if 2021 is a down year. That is another piece of the puzzle. We will know more as the year progresses.

MR. MARTIN: There seems to be a disconnect here. Some of you are out of the market in terms of capacity to do additional 2020 deals. Two of you are down to one or two more 2020 deals. And yet the volumes you expect this year are in some cases double what you did last year. How do you reconcile that?

MR. CAPPS: It depends on whether the focus is on funding existing commitments or writing new commitments. I was speaking mainly to funding in 2020 of existing commitments.

Many developers are having difficulty finding it.

It was a very robust last quarter of 2019 and a very robust first quarter of 2020, which is the reason for our large increase in tax equity funded this year even though we are not issuing new commitments. At this point in a normal year, we would be focusing on the next year ahead.

MR. MARTIN: So double the funding this year, but in terms of closing new deals in 2020, the number may be down.

MR. CAPPS: It is probably flat. / continued page 6

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the order. The answer is probably not, but the answer is still unclear. The Department of Energy declined to draw such a clear line in a set of frequently asked questions and answers in June.

THE CALIFORNIA LEGISLATURE may shield nonresidential solar projects from a property tax increase that is on the state ballot this November.

The legislative maneuver is controversial and may end up in court.

Californians will vote this November on a "split-roll" ballot initiative — called Proposition 15 — that would increase property taxes on business property by essentially splitting the property tax roll between residential and business property.

The California constitution limits property taxes on real property currently to 1% of the "full cash value," defined as the amount the owner paid to acquire the property or have it newly constructed. The assessed value can go up by inflation, but not by more than 2% a year. Otherwise, the property cannot be reassessed until there is a change in control.

Newly constructed active solar systems completed before 2025 get a pass on property taxes altogether until there is future a change in control.

If the split-roll initiative passes, nonresidential solar projects will become subject to property taxes and annual reassessments at full value beginning in 2022. (For more details, see "California split-roll initiative upsets solar developers" in the June 2020 *NewsWire*.)

Advocates of Proposition 15 say the effect of the initiative on solar was inadvertent. They support a bill that solar companies are trying to put through the state legislature that would reclassify nonresidential active solar systems as "personal property" and then exclude them from tax as long as they remain property of the original owner. The legislature has limited authority under the state / continued page 7

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Other Market Shifts

MR. MARTIN: It seems like spreads had widened by about 50 basis points in April and May compared to the start of the year. Where would you say they are today?

MR. MCCLAIN: About the same.

MS. MCLEAN: They are at least 50 basis points wider at this point.

MR. COHEN: I concur with that. Yields have moved north, particularly for anyone looking to secure remaining 2020 capacity. The 2021 supply has also shrunk, and it is affecting 2021 yields as well.

MR. MARTIN: Are tax equity deals taking longer to close this year because of COVID?

MS. MCLEAN: I don't think so.

MR. HEINTZ: I don't see any difference either.

MR. COHEN: I think the biggest difference is around getting the third-party deliverables lined up. To the extent those are in order and moving efficiently, we have not seen any delays. To the extent that the independent engineers or other consultants are backlogged due to COVID, that has caused some delays. That is really the only thing that we have noticed.

MR. MARTIN: Is creditworthiness of corporate offtakers becoming a concern?

MR. MCCLAIN: It is always a concern for us with the sale-leaseback product. Sale-leasebacks are long-term structures, so the offtaker credit and industry profiles are of the highest importance to us.

MR. CAPPS: I agree. We do the sale-leaseback product as well, which is more long dated. Even before our pause, when we were looking at some distributed generation portfolios, we were probably tightening the minimum credit standards. There has definitely been a tightening there.

MR. MARTIN: What about COVID delays pushing 2020 projects into 2021? Is that happening?

MS. MCLEAN: That is one of the biggest reasons why we see investors being a little tentative about 2020 commitments. Having a number of projects in the pipeline that are supposed to be placed in service in 2020, but that could slip into 2021, obviously could affect investor tax strategies.

Our sponsors have to be proactive in managing this risk and to get ahead of any supply-chain or construction-site issues early.

Communication with our sponsors has been terrific. They have been giving us construction-progress reports and letting us know where they see issues so that we can help them to pivot or find solutions, such as helping to find a new equipment supplier. So far we have not had a deal slip because we are watching this closely, but I think most of us are thinking some slippage is very likely to happen.

MR. MARTIN: What happens if you have a deal slip? If you think slippage is a big risk, do you not do that deal in the first place? Do you just reduce the pricing if it slips?

MS. MCLEAN: These issues are negotiated up front. Delays are not necessarily new to us because of COVID. Delays happen for many reasons. We try to be realistic in our projections.

We focus less when doing deals on how to adjust pricing if the deal slips. It is hard to predict future pricing. The appropriate thing is to make sure we structure the deal with a realistic timetable.

MR. MARTIN: What else has changed this year compared to where the market was before the economic shutdowns in March?

MR. HEINTZ: One thing we have been tracking is the hardening of the property and casualty insurance markets. That has required additional analysis by our risk and credit folks. We have been seeing more limits on certain catastrophic risk in property and casualty coverage.

MR. COHEN: The difficulty finding tax equity using partnership-flip and inverted-lease structures is driving some developers to take a closer look at sale-leasebacks.

MR. MCLAIN: We are seeing people that in the past have not considered a sale-leaseback also take another look at it.

MR. MARTIN: Sale-leasebacks do not work for projects — like wind farms — on which production tax credits will be claimed, but they work for solar and fuel cell projects with investment tax credits. In which solar market segments are you seeing growing interest in sale-leasebacks?

MR. MCLAIN: We have been doing both utility-scale and the larger distributed solar-type projects. I see the distributed sector definitely taking a fresh look at sale-leasebacks. On the utility-scale side, the projects that work best have long power purchase agreements, especially if the PPA price escalates over time. We can be pretty competitive with the partnership-flip product structures with those types of PPAs.

Possible Changes in Law

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

The US Comptroller of the Currency asked for comments in late June about whether national banks should be prohibited from providing tax equity in partnership-flip structures for residential and C&I solar projects. Of course, not all banks invest as the regulated bank. If they are investing through a bank holding company or non-bank affiliate using merchant banking authority, they would not be affected. What are you hearing from your bank regulatory people? Could this affect the availability of tax equity for the rooftop solar market?

MR. HEINTZ: Most of our bank-level investing has been limited to utility and municipal utility types of transactions. We read the notice to say the Comptroller is considering more flexibility than it has shown to date on these asset classes. So this could lead to more tax equity for rooftop solar.

MR. MARTIN: So possibly a favorable development.

Next item: the US Chamber of Commerce, the National Association of Manufacturers and a coalition of individual companies are pushing for a tax credit refund proposal in Congress as part of the next economic stimulus bill. Tax credits claimed in 2019 or 2020 — or carried from as far back as 20 years ago into those two years — would be refunded by the IRS in cash. Would this put any tax equity investors back into the market this year? How significant a proposal is it?

MR. CAPPS: It could be significant. It might change our view about the need for a pause in further investments. It is the potential tax credit carryforwards that impact the CCAR. If we did not have to carry tax credits forward, that could very well put us back in the market.

MR. MARTIN: I should note that the proposal did not make the cut last night in the bill that the Senate Republican leadership released. However, there could be several weeks of negotiations.

MR. MCCLAIN: I agree with Robert. It would have a significant impact on our outlook.

MR. MARTIN: The renewable energy trade associations have been pushing a more narrowly-targeted proposal. The government would refund 85% of tax credits on renewable energy projects put into service after the proposal is enacted. There would be no time limit. Would you expect banks that are having tax capacity problems to come back into the market if they can bridge a refund and claim depreciation?

MR. HEINTZ: It would add additional capacity to the market.

MR. MARTIN: During the Treasury cash grant era, there were quite a few banks that had no tax capacity, but were investing tax equity as a bridge to the refunds.

Next question: If the Democrats / continued page 8

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constitution to exempt real property from property taxes, but it can exempt personal property by at least a two-thirds vote in both houses.

The bill, SB 364, passed the state assembly in early August by a 56-12 vote. It must also pass the Senate before the current legislative session ends at the end of August, and the governor would have to sign it.

The California Assessors' Association and various business groups oppose the bill and say they may challenge its constitutionality in court.

The bill has a sunset clause. It would be automatically repealed as of January 1, 2021 if the ballot initiative fails in November.

SOME ANALYSTS are questioning whether SOFR — the new base interest rate that will replace LIBOR in US contracts — is too volatile to serve as a good replacement.

Most debt in project finance transactions and many swaps, hedges and other contracts are tied to LIBOR. For example, a loan might require payment of floating interest at a spread of 137.5 basis points above LIBOR.

The UK Financial Conduct Authority has not committed to publishing LIBOR past 2021.

The Federal Reserve Bank of New York began publishing a secured overnight financing rate, or "SOFR," in April 2018 as a replacement for LIBOR for US-dollar denominated instruments. Other countries have chosen other reference rates for their currencies. For example, the UK will use a sterling overnight index average called SONIA, and Japan will use a Tokyo overnight average rate called TONAR. Separate reference rates have been selected for the Eurozone, Canada, Switzerland, Australia and Hong Kong.

Debt instruments and non-debt contracts that refer to LIBOR will have to be amended or replaced.

According to some reports, only a quarter of companies may be prepared for the transition.

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win in November, at least two tax law changes are likely. One is extensions of renewable energy tax credits. The other is an increase in the corporate tax rate, possibly to 28%. How do you expect these changes to affect the market?

MR. COHEN: They would make what we are developing rather late in the game — if you think about when the credits are set to sunset at this point — a lot more viable for us in the medium to long term. They would create more tax equity business.

MS. MCLEAN: I agree with that. Reducing the corporate tax rate to 21% led to a reduction in tax capacity after 2017.

Large bank loan loss provisions are making it tough for banks to forecast tax capacity.

MR. MARTIN: *The Wall Street Journal* reported this morning that the Biden campaign is proposing a 15% corporate minimum tax. Basically if a company has more book earnings than it reported in taxable income, it would have to pay 15% of the book earnings as an alternative minimum tax. How do you see such a tax affecting banks' appetite for tax equity if it is enacted?

MR. CAPPS: It just adds one more layer of analysis that the banks have to do to forecast tax capacity. It makes the exercise more complex.

MR. MARTIN: How are you seeing change-in-tax-law risk addressed in current deal papers?

MS. MCLEAN: We have not changed anything. We already were forecasting that there might be more changes in tax laws.

MR. MARTIN: What does that mean in practice?

MS. MCLEAN: Tax rates are expected eventually to increase. This might work a little in favor of sponsors or investors. We are not taking a different approach in how we write our deal papers.

MR. MARTIN: In most deals, the tax rate floats anyway. So if the transaction has a yield-based flip and the tax rate increases early in the life of the deal, the deal might flip sooner. If the rate change comes later in the life of the deal, it will delay the flip date.

MS. MCLEAN: That's right.

MR. CAPPS: We are not taking a different approach. In the sale-leasebacks, the investor bears the brunt of risk the tax rate will change. That is a risk the investor takes.

MR. MARTIN: Is anyone putting in special provisions to deal with change-in-tax-law risk at this point? [Pause] I will take that as a "no."

MR. MCCLAIN: Our transaction papers make it a condition to funding that there has been no change in tax law. Other than that, we are doing nothing new at this point.

Current Issues

MR. MARTIN: Projects have to be under construction by a deadline to qualify for tax credits, but it seems the link between the construction effort and the project claiming the tax credits is becoming more and more attenuated.

Sponsors are doing less and less physical work to start construction. Transformers may be ordered, but delivered in three or four years. The developer may tell the manufacture not to do any more work after the construction-start deadline until it receives a notice to proceed. Some wind developers are relying on physical work on a single wind nacelle. Physical work on one project is being moved to a different one.

Are you financing projects that start construction under the physical work test, and if so, what lines are you drawing? Yonette McLean.

MS. MCLEAN: Thank you for that, Keith. We have done one deal that was greyish, I will call it. I would not want to view it as a precedent for what we might do in the future. It put a fair amount of strain on our tax advisers, including counsel.

We have seen the transformer strategy. It is acceptable given the right facts. However, the physical work test is a heavier lift and less than ideal.

MR. COHEN: We look at it on a case-by-case basis, but physical work cases require greater care.

This also comes up in cases where we are acting as a lender and bridging to the tax equity, in which case we will want to be conservative. The tax equity is our takeout. Banks are inherently risk averse in nature, so they tend to steer toward the more conservative side.

MR. MARTIN: The next question is for the three of you who are doing sale-leasebacks. Some companies may end up looking everywhere they can this year for cash. How much of a market do you think there is for depreciation-only sale-leasebacks of existing assets where the lessor claims a 100% depreciation bonus?

MR. MCCLAIN: We did one such deal last year. Since the structure works pretty efficiently, it really comes down to the sponsor's objectives.

MR. COHEN: Scott, we worked on that deal with you, and I think it worked well, partly because the sponsor was sophisticated and a strong credit. I think it is something that we will start to see more of as projects move beyond the initial financing or tax equity term.

MR. MARTIN: The rent is fully deductible, whereas the ability to deduct interest would be capped, so that may also steer people to this form of refinancing.

I have two more questions. How much appetite do you think there will be, once tax capacity recovers, for carbon capture projects?

MR. HEINTZ: For us, as long as we still have access to high-quality solar projects with investment tax credits, we are unlikely to do carbon capture.

MR. MARTIN: Why?

MR. HEINTZ: Part of it is the need to go through internal new-product approvals. Moving into new asset classes can be challenging. If we have enough pipeline by way of quality projects on the solar side, we are unlikely to venture into a different asset class.

MR. MARTIN: Does anyone have a different view?

MR. MCCLAIN: No. I feel Eric's pain about the new approval process. And my understanding is these projects throw off pre-tax losses. That would not be something of great interest to us. As long as we have good solar projects where we can get pre-tax income, carbon capture credits would not be of interest.

MS. MCLEAN: I don't think investors are completely uninterested. It is too early at the moment for them to get excited about it.

If the credit looks more like a PTC, that will probably reduce the investor interest. The current */ continued page 10*

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Many banks are choosing an approach where the parties decide later what to do rather than hard wiring a change today.

LIBOR reflects interest rates that banks charge each other in interbank lending in the London market.

SOFR is tied to rates in the US repo market.

SOFR dropped to 0.26% on March 16, doubled the next day to 0.54%, and then fell to 0.10% the day after. Strains in the repo market pushed it above 5% last September.

The Alternative References Rates Committee that has been helping to manage the transition in the United States said the following in a list of frequently asked questions in early 2019: "Overnight rates in the repo market are inherently somewhat volatile, and the dynamics that generate much of the volatility are well-known and somewhat predictable. For example, settlements of Treasury securities typically cause fluctuations in rates throughout the month, and in particular on coupon settlement dates at the middle and end of months, while balance-sheet management by some repo market participants contributes to temporary volatility around quarter-end dates."

SOFR appears to be more sensitive to real-time market dynamics, while the three-month average of SOFR is less volatile than three-month LIBOR.

Some smaller and mid-size banks are using Ameribor, which is tied to rates set by the American Financial Exchange, an electronic exchange where banks borrow and lend short-term funds.

US OFFSHORE WIND will come close to overtaking offshore oil and gas over the next 10 years in terms of new capital expenditures, according to consultancy Wood Mackenzie. The group projects $78 billion in spending on offshore wind compared to $82 billion on offshore oil and gas development through the end of the decade. */ continued page 11*

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sentiment is there is so much solar ITC product right now that investors have no need to look at new products.

MR. MARTIN: Last question. As Scott said, carbon capture deals are likely to run pre-tax losses, so the accounting treatment is difficult.

They apparently do not work with the HLBV method of accounting and would work only with the proportional amortization method like the Financial Accounting Standards Board authorizes for low-income housing investments. At least, that is what some people are arguing. Do you have any view on whether the current accounting treatment is a killer for this type of deal?

MR. MCCLAIN: Unless the bank has a reason to want to do such a deal as part of an ESG initiative, we prefer deals that generate earnings on a pre-tax basis.

MR. CAPPS: We can handle pre-tax losses. They are not a deal killer, but we certainly have to manage this on an overall portfolio basis. ◎

PURPA Overhauled

by Robert Shapiro and Caileen Kateri Gamache, in Washington

Independent cogeneration and small renewable energy projects — known as "qualifying facilities" or "QFs" — have lost key protections from merchant risks that they have relied on to help secure financing for the past 40 years.

This is one of many takeaways from changes that the Federal Energy Regulatory Commission made in July in how it implements a 1978 law called the Public Utility Regulatory Policies Act or PURPA.

After a four-year period of technical conferences and a proposed rulemaking, FERC issued a final rule on July 16 that substantially revised the PURPA rules for QFs, particularly renewable energy projects. (For additional background, see "PURPA Projects Become More Difficult to Finance" in the October 2019 *NewsWire*.)

The FERC rules in this area must be followed by the states. However, FERC is now greatly expanding the discretion of states to determine when a project deserves a binding power contract and to decide how that contract should be priced. The new FERC policy also allows potential power purchasers to challenge whether affiliated projects located fewer than 10 miles apart should be considered a single project for purposes of eligibility for PURPA benefits.

PURPA requires utilities to buy electricity from certain power projects, but only projects up to a certain size. If two projects are considered a single project because of overlapping ownership, then they may no longer qualify.

The FERC final rule is subject to rehearing within 30 days, and it may be challenged in court. We anticipate both will occur. The lone Democrat on the commission said in a published dissent that the rule is invalid.

The final rule is in FERC Order No. 872.

Developers and lenders have been asking lots of questions since FERC acted on July 16. A list of the most frequently asked questions — and answers — is at the end of this article.

Background

PURPA exempts independent power projects called QFs from typical utility regulation and requires utilities to buy power from such projects at a fair price.

PURPA required FERC to issue implementing rules that the individual states would then be required to implement. FERC determined that a fair price would be the utility's "avoided cost," or the cost that the utility would otherwise incur to generate the electricity itself or buy it from an alternate source.

FERC gave QFs the option to obtain an avoided-cost rate based on the real-time cost at the time of delivery of the power or to lock in rates when the power contract is signed based on the projected avoided cost of power over the term of the contract.

FERC gave the states considerable latitude in determining the avoided costs of their regulated utilities. Unregulated utilities, like most municipally-owned utilities and electric cooperatives, had to "self-implement" the PURPA rules as well.

Although PURPA has been largely eclipsed by state renewable portfolio standards in 29 states and the District of Columbia that require utilities to deliver a substantial percentage of the electricity they supply from renewable sources, PURPA remains relevant for smaller projects in organized markets served by regional transmission organizations, or RTOs, and in the states that lack an RPS standard. Therefore, the latest rule changes are more likely to affect projects in the non-RPS states.

Floating Prices

Fixed-price power contracts are now discretionary.

FERC has decided that states are only required to fix rates if there is a separate capacity component to the avoided-cost rates. The states have discretion to approve avoided-cost energy rates that vary with the market rates at time of delivery of the energy, even though the utility may be buying electricity under a long-term contract.

To be clear, the new rules allow the states to continue to set fixed avoided-cost rates for energy for the term of the contract if they choose to do so. Parties may also continue to enter into PURPA contracts with terms that vary from the PURPA rules by mutual agreement.

Many intervenors in the FERC proceeding challenged the proposal to make fixed energy rates discretionary at the state level, arguing that floating rates would make project financing difficult, if not impossible. FERC justified the switch to short-term avoided cost rates on the grounds that many non-QF renewable energy projects (mostly those whose sizes exceed the 80-megawatt ceiling for QF eligibility) have been able to sign fixed-rate contracts without having to fall back on a statute ordering utilities to sign.

What FERC ignored is that most of the renewable power purchase agreements today are being signed either by utilities that are under state obligations to / continued page 12

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Projects in federal waters off the Atlantic coast have been in limbo since August 9, 2019 when the US Department of Interior placed a hold on issuing final environmental impact statements needed to start construction of individual projects until it could complete a cumulative-impacts analysis of all the projects that are expected to be built as a result of foreseeable state procurements. The department lifted the hold in June. The first "record of decision" is expected by December 18, 2020 for the Vineyard project off Massachusetts. Other construction permits should follow for other projects.

Meanwhile, offshore wind companies managed to strip a provision from the defense authorization bill in the House in late July that would have required specialized vessels used to install offshore wind turbines to comply with the Jones Act, meaning only US-flag vessels could be used. There are no such US-flag vessels currently. The first specialized US-flag vessel is not expected to be available until 2023 and has been ordered built to assist with installation of a Dominion Energy project off the Virginia coast.

US developers must reserve specialized installation vessels from Europe well in advance of need.

The House provision would have included a waiver mechanism, but the ability to get a waiver and for how long would have remained uncertain.

NATIONAL BANKS have been given clearer guidelines by the US Comptroller of the Currency about when they can participate as tax equity investors in partnership-flip transactions.

The guidelines are merely proposed. The Office of the Comptroller of the Currency, or OCC, released them in July. They are an effort to write into regulations standards that the OCC developed in two interpretative letters for banks wanting to invest / continued page 13

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comply with state RPS standards or by corporations that are trying to meet internal goals to reduce their carbon footprints or lock in long-term power prices. The utilities in RPS states recognize the value of fixing rates for periods of 20 to 30 years while they are trying to comply with renewable purchase mandates that are increasing over time.

FERC also ignored the dramatic reduction in solar and wind electricity prices that has occurred over time. It arguably rebuts the historic claims by certain utilities and state commissions in non-RPS states that fixed prices lead inevitably to prices that exceed the utilities' avoided costs over time.

Projects with PURPA contracts may be harder to finance in the future.

Under the new FERC policy, there will be a rebuttable presumption in the future that the locational market price, or LMP, in organized markets is the "as-available" avoided cost of utilities.

The commission said that states outside the organized markets can base avoided-cost determinations on a liquid market hub (like Palo Verde or Mid-Columbia) that is used by the particular utility for some of its transactions or use a formula based on a natural-gas index and specified heat rates for a combined-cycle gas-fired power plant.

FERC said that states can also use prices based on the outcome of competitive solicitations as long as the solicitations are open to "all sources" and are not limited, for example, to renewable energy. Any such solicitations must be evaluated by an independent administrator and be conducted at regular intervals.

At bottom, states and utilities that have historically promoted QF facilities will continue to use fixed energy rates in long-term contracts, and states and utilities that have historically discouraged QF facilities will use the new, more flexible rules to limit their purchases to "as-delivered" or "as-available" spot energy rates.

One-Mile Rule

With limited exceptions, PURPA applies only to renewable energy projects that are no larger than 80 megawatts in size. Smaller projects qualify for additional regulatory benefits.

Project capacity is measured by combining renewable generating equipment, such as turbines or solar arrays, with any affiliated equipment that uses the same fuel source at the same "site." Congress authorized FERC to determine what constitutes a "site."

In the past, FERC used a one-mile rule. Equipment within one mile apart has been treated as on the same site; equipment more than one mile apart is considered part of a different project.

The new FERC policy draws three lines. Equipment within one mile apart is on the same site. Equipment 10 or more miles apart is not. There is now a "rebuttable presumption" that equipment in between one and 10 miles apart is on different sites: utilities can challenge the presumption by showing common characteristics between the projects.

Organized Markets

Congress amended PURPA in 2005 to allow FERC to exempt utilities in organized markets from the mandatory purchase obligation.

FERC used this authority to exempt utilities in areas with competitive spot markets, like PJM, ERCOT, CAISO, MISO, NYISO and the New England ISO, from having to buy electricity from projects that are larger than 20 megawatts in size.

FERC decided that requiring smaller projects to comply with complicated RTOs rules for electricity sales would be both too expensive and too burdensome, depriving small projects of nondiscriminatory access to such markets.

Under the new policy, utilities in organized markets will no longer have to buy electricity from projects that are more than five megawatts in size. This was a compromise. FERC had originally proposed to reduce the figure from 20 megawatts to one megawatt.

FERC kept the 20-megawatt standard for cogeneration facilities on the theory that electricity generated at such facilities is a byproduct of making steam for an industrial use, and owners of cogeneration facilities might not be as familiar with energy markets and the technical requirements for electricity sales.

FERC said it will consider proposals to terminate the mandatory purchase obligation for individual utilities operating outside organized markets run by RTOs.

FERC said it might be possible for such a utility to demonstrate that it is in a workably competitive market by demonstrating that it uses market hubs or competitive solicitations to buy and sell electricity. The utility would have to demonstrate that the particular market is of comparable quality to the real-time and day-ahead markets that exist in most RTOs.

Commercial Viability

PURPA required utilities to enter into a "legally enforceable obligation" to buy electricity from qualifying facilities, a phrase FERC never clearly defined. Its meaning has led to many disputes at the state level.

The new policy requires the avoided-cost price for electricity to be established when the legally enforceable obligation is established, but FERC has left wide discretion to the states to determine when that occurs.

An independent generator seeking a power purchase agreement or other "legally enforceable obligation" must demonstrate commercial viability and a financial commitment to construction of its project pursuant to objective and reasonable state-determined criteria.

FERC made clear that "the states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment, albeit subject to the criteria being objective and reasonable."

FERC said a generator might show commercial viability by showing that it is in the process of completing at least some key steps. For example, it has site control adequate to build the project at the proposed location, and it filed an interconnection application with the local utility or grid operator.

FERC said states can require the generator to show that it has submitted applications and paid the / *continued page 14*

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in tax equity transactions structured as partnership flips. (For earlier coverage, see "The Volcker rule" in the February 2014 *NewsWire* and "Wind developers helped by two favorable rulings" in the March 2006 *NewsWire*.)

The regulations apply to national banks engaging in tax equity transactions directly as the deposit-taking bank. Many banks use non-bank affiliates or other ways to invest, and some other banks investing tax equity are state banks rather than national banks.

National banks have authority to move beyond traditional loans to accommodate the demands of the market as long as each such transaction is functionally equivalent to a loan.

Under the proposed regulations, a tax equity partnership would have to satisfy a series of requirements to qualify as functionally equivalent.

The most burdensome is the bank must notify the OCC in writing before engaging in each transaction. The notice must include an evaluation of the risks posed by the transaction.

Beyond that, the transaction must be necessary to make tax credits or other tax benefits available to the bank.

It must be "of limited tenure and not indefinite." The transaction "would need to have a defined termination point." Giving the sponsor a call option to acquire the bank's interest at or near fair market value satisfies this requirement, the OCC said. "The proposed rule would permit a national bank or federal savings association to retain a limited investment interest [after the flip] if that interest is required by law to obtain continuing tax benefits from the transaction."

The bank must not place "undue reliance on the value of any residual stake in the project or the proceeds of disposition" after the tax credit recapture period.

The bank must not count on appreciation in value of the underlying project.

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filing fees for all necessary local permitting and zoning approvals.

As to "financial commitment," FERC was less specific. It said that "demonstrating the required financial commitment does not require a demonstration of having obtained financing."

Once again, states and utilities that historically have encouraged QF development can be expected to take a lighter hand in establishing conditions before a qualifying facility is entitled to a "legally enforceable obligation" than states and utilities that have historically opposed QF development.

FERC declined to decide whether utilities must offer a minimum contract length. This will be left to the states to decide.

Common Questions

Project developers and lenders have been asking lots of questions since FERC acted. Here are the most common questions.

1. My solar project QFs are each 70 megawatts in size, and they are nine miles apart. Are they no longer QFs?

A: The new rules only apply prospectively, and FERC will not permit any "disturbance" of QF certifications filed before the effective date of Order No. 872. If the projects file to re-certify QF status due to a substantive change, they will remain separate projects under a rebuttable presumption that they are at separate sites, but their status will become vulnerable to challenge and potential revocation. A project will retain QF status, even if challenged, until FERC finds the project does not qualify as a QF.

2. How is the distance between two sets of wind turbines or solar arrays measured?

A: The distance is measured from the edge of the closest "electrical generating equipment." Inverters are considered "electrical generating equipment," but other assets such as substations and transformers are not. For a wind farm, the relevant point is the edge of a wind facility tower and not the wingspan of the turbine blades.

FERC is revising its Form 556 for QF status to require geographic coordinates of these points so that it can check the distance between the applicant and any affiliated QFs using the same resource located less than 10 miles away.

3. Should we expect to have to defend all of our future QF filings?

A: Yes, for renewable energy projects that would be more than 80 megawatts in size if combined with an affiliated project using the same resource more than one, but less than 10, miles away.

A utility that is required to buy electricity from a project may want to terminate the obligation by arguing that other turbines or solar arrays more than one mile, but less than 10 miles, away are part of the same project.

Any interested party may file a request for a declaratory order challenging the QF status of a project. (There is a filing fee.) This was true under the old rules, but now there is a better chance of disqualifying a project.

The filing fee is now waived for challenges that are made within 30 days after a project files for initial certification or re-certification of QF status.

FERC's regulations will continue to state that a QF that "fails to conform with any material facts or representations" of its last FERC Form 556 QF filing may not rely on its QF status.

Under the new policy, only those re-certifications that report "substantive" changes are subject to challenge. Importantly, FERC views a change of 10% or more direct or indirect equity interest in a QF as a "substantive" change, irrespective of the fact that ownership is not an element of QF eligibility.

The revised FERC Form 556 will include space to make a defensive argument as to why the project should not be aggregated with affiliated projects located less than 10 miles away. Some industry participants estimated this may require an additional 90 to 120 hours to prepare the FERC Form 556.

4. Does the one-to-10 mile rule also govern whether a QF qualifies for regulatory exemptions?

A: Yes.

A major benefit of QF status is broad exemption from utility regulation under the Federal Power Act, the Public Utility Holding Company Act and state utility laws.

For many renewable energy projects, these exemptions apply only if the project is 30 megawatts or less in size (and additional exemptions are available if a project is 20 megawatts or less in size). Historically, FERC has relied upon the one-mile rule to determine whether a project qualifies. It will continue to do so under the new policy.

However, projects located more than one mile apart will be presumed to be located on separate sites so that their capacities will not be aggregated, unless and until a protest is filed and FERC finds they are located on the same site. If a protest is filed, it may be prudent for the project to start planning to comply with public utility regulations if there is a significant risk it may lose exemptions.

5. Does the one-to-10 mile rule apply to the five-megawatt presumption for determining whether a project lacks meaningful access to competitive markets?

A: No.

In contrast to determining eligibility for QF status, which focuses on whether facilities are located at the same "site," the determination of whether a QF has meaningful access to a competitive market focuses on the QF itself.

However, under the new policy, the fact that affiliated facilities are nearby may be relevant when evaluating whether a QF has nondiscriminatory access to a competitive market in a FERC section 210(m) proceeding. That is a proceeding to determine whether a utility may terminate its mandatory purchase obligation.

6. If two sets of affiliated wind turbines or solar arrays are within 10 miles of each other, how will FERC decide whether they are located at the same "site"?

A: The determination will be fact based, and no one fact or factors will be determinative. FERC said it will take into account physical characteristics such as the following:

> infrastructure, property ownership, property leases, control facilities, access and easements, interconnection agreements, interconnection facilities up to the point of interconnection to the distribution or transmission system, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, connections to the electrical grid, evidence of shared control systems, common permitting and land leasing, and shared step-up transformers.

FERC said it will also look at the degree of common ownership and other characteristics such as the following:

> whether the facilities in question are . . . owned or controlled by the same person(s) or affiliated persons(s), operated and maintained by the same or affiliated entity(ies), selling to the same electric utility, using common debt or equity financing, constructed by the same entity within 12 months, managing a power sales agreement executed

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The tax equity documents must contain terms and conditions equivalent to those found in documents governing typical lending transactions. The bank must use underwriting criteria that are substantially equivalent to those used when making a traditional commercial loan.

The bank must be a "passive investor in the transaction and must be unable to direct the affairs of the project company." Thus, it cannot direct the day-to-day operations of the project. Temporary management activities in the context of a foreclosure or similar proceedings do not violate this requirement.

The bank cannot control the sale of energy from the project.

The accounting treatment of tax equity transactions may differ from a loan.

The dollar amount of all the tax equity transactions engaged in by the bank cannot exceed 5% of the bank's capital and surplus without OCC approval, and in no event can it go above 15%.

The bank must monitor its transactions to ensure they are conducted in a safe and sound manner.

The OCC asked for comments about whether it should bar banks from entering into residential and C&I solar transactions.

An OCC lawyer said there is no interpretive letter on point, and the OCC is trying to understand any issues presented. She said not to read any more than that into the request for comments.

Another issue about which the OCC asked for comments is whether the tax equity papers should require banks to have the option to replace the sponsor or manager under certain conditions or be required to be indemnified for breaches of tax representations and other legal risks.

Other open questions are whether sponsors must guarantee payment of any indemnities the bank is owed and whether banks should be allowed to participate in tax equity transactions through "fund-based structures."

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> within 12 months of a similar and affiliated small power production qualifying facility in the same location, placed into service within 12 months of an affiliated small power production QF project's commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts.

The burden of proof that the projects are at the same site is on the utility or other person protesting separate treatment.

7. Do solar rooftop companies that have been tracking distance for purposes of the one-mile rule, mostly to determine whether to file a FERC Form 556, now need to track 10-mile distance?

A: No. FERC did not change the standard and, in fact, it confirmed the one-mile rule still applies for determining whether to file a FERC Form 556.

If FERC determines that rooftop installations located more than one, but less than 10, miles apart are on the same site, then the one-megawatt threshold for filing will need to be re-evaluated.

As an aside, FERC adopted a new re-certification policy for rooftop solar. Any re-certifications should be filed on a quarterly basis, within 45 days after the end of the calendar quarter.

8. The power purchase agreements for two wind farms owned by the same company require the projects to maintain QF status throughout the PPA terms. Each project is 50 megawatts. The projects are nine miles apart. Are they at risk of losing their PPAs?

A: Not unless there is a substantive change in the projects that requires re-certification in the future. The new rules apply prospectively. Even if the projects are re-certified, they will be protected by a rebuttable presumption unless and until FERC determines they are located on the same site.

Many utility PPAs with renewable energy projects require that QF status be maintained. The specific language used in the contract is important. For example, the contract may include a "change-in-law" provision that applies in this situation.

9. The PPA for an 18-megawatt solar facility in MISO terminates if the utility is no longer obligated to purchase power from QFs. Will the PPA terminate?

A: Probably not. Utilities in MISO must purchase from QFs that are up to 20 megawatts in size, unless they can prove the QF has nondiscriminatory access to the MISO market. The size threshold has been reduced to five megawatts under the new policy. The new policy will only apply prospectively, and it "does not permit disturbance of existing contracts or [legally enforceable obligations] or existing facility certifications."

The specific terms of the PPA should be reviewed to determine whether there are any other relevant provisions.

10. Is there anything a lender or equity investor should include to protect its interests in a loan or investment agreement currently under negotiation?

A: If the project is not in an organized market and has a PPA that requires it to be a QF, then the lender should consider whether to ask the sponsor to represent and covenant that the project is not, and will not be, located within 10 miles of an affiliated QF using the same resource if the two projects combined would exceed 80 megawatts in size.

For projects in organized markets, some investors rely on the mandatory purchase obligation of utilities to gain comfort with the "tail" risk after the PPA terminates. If the project is greater than five megawatts in size, then that mandatory purchase obligation should no longer be relied upon.

Lessons Learned From the PG&E Bankruptcy

Two senior bankers who are active in the California market, and the general counsel of a prominent renewable energy developer based in California, talked in late July about what effect the PG&E bankruptcy has had on the ability to finance renewable energy projects in California and what, if anything, they are doing differently in new transactions to reflect lessons learned from the bankruptcy. The following is an edited transcript.

The panelists are Paul Pace, senior vice president and team leader at Key Bank, Pascal Uttinger, managing director at MUFG, and Kevin Malcarney, general counsel and senior vice president of Clearway Energy. The moderators are Jim Berger with Norton Rose Fulbright in Los Angeles and Christy Rivera with Norton Rose Fulbright in New York.

Still Lending?

MR. BERGER: Paul Pace, will Key Bank lend to a project whose main source of revenue is a long-term contract to sell electricity to a California investor-owned utility? And do you differentiate between Pacific Gas & Electric, on one hand, and Southern California Edison and San Diego Gas & Electric on the other?

MR. PACE: Yes, we will lend to California utilities.

Do we differentiate? For a while we certainly differentiated in that PG&E was un-financeable while it was in bankruptcy. Today, there are other issues for why PG&E is a little different than the other two utilities. We check the credit ratings and assess where our claims will be on both a secured and an unsecured basis. That does not rule out a loan at this point. It is more of a matter of how best to deal with the risk.

We look at the regulatory environment in the state as a whole. The state regulators did a good job of balancing what was right for the bondholders, what was right for wildfire claimants, and what was needed ultimately to keep the lights on and keep pace with milestones under the renewable portfolio standard.

The bottom line is we are still willing to lend to projects that have offtake contracts with investor-owned utilities in California.

MR. BERGER: Pascal Uttinger, same question. Will MUFG lend to projects with California utility offtake contracts, and do you differentiate between PG&E, on one hand, and SCE and SDG&E on the other?

MR. UTTINGER: The short answer is / continued page 18

IN OTHER NEWS

A UTILITY TAX EQUITY FILING with the Public Service Commission of Wisconsin reveals interesting data points about the current tax equity market.

The Wisconsin Power and Light Company asked the commission for permission in late May, and updated the filing in August, to acquire the rights to six utility-scale solar projects from Geronimo Energy, NextEra Energy Resources, Ranger Power and Savion with a total capacity of 675 megawatts. The utility plans to build 1,000 megawatts of solar by the end of 2023.

The projects will be acquired before construction. The developers may or may not see them through construction.

All of the projects were considered under construction for tax purposes in 2019 so that they qualify for 30% investment tax credits. The utility will liquidate the existing project companies and take possession of the projects directly, but then sell the projects to new special-purpose project companies that will be owned by one or more tax equity partnerships before mechanical completion. The sales may step up the tax bases on the projects for calculating investment tax credits to fair market value.

The utility said in the filings that it has term sheets from three tax equity investors and is projecting flip yields of between 6% and 7%.

The tax equity investors will take 15% to 35% of the cash before the flip and 5% after.

Tax equity is expected to account for 35% to 45% of the capital stack.

The electricity will be sold into MISO. The utility will enter into contracts for differences with the project companies to put a floor under the electricity price.

It plans to put its investment in the tax equity partnerships into rate base and recover the rate base investment over 30 years. It told the commission the tax equity partnerships will save its customers $129 million on a present-value basis. / continued page 19

California

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yes, we are still lending, and I echo the comments that Paul Pace made about a supportive regulatory environment in California.

MUFG has been an active lender to California utilities and to projects with offtake contracts with California utilities for years. We witnessed both PG&E bankruptcies first hand and have a lot of direct experience in the California market. We concluded early on that PG&E was unlikely to abrogate any contracts for renewable electricity or for gas-fired generation, especially with the backdrop of the state renewable portfolio standard and the bad precedent that abrogating any contract would set.

Like most, if not all, project finance lenders, we have concentration limits for California risk and certain offtake risks. As long as we operate within our own concentration limits, we expect to remain active in California.

Moving to the second part of your question — whether we view PG&E differently than the other utilities — there are a couple points to make.

Banks are lending again to finance California projects.

It makes sense that the market assigns a premium to PG&E versus the other two utilities. We currently see a premium in the 25- to 50-basis-point range for project finance transactions. PG&E is not rated investment grade as a corporate borrower. We expect the premium to disappear over time as the bankruptcy gets smaller in the rear-view mirror and PG&E is ultimately upgraded.

At least two deals are in the market currently with PG&E offtake contracts, and we expect those transactions to go well.

MR. BERGER: Kevin Malcarney, how does Clearway, as a long-term owner of assets, approach projects with California investor-owned utilities? And do you differentiate between PG&E, on the one hand, and SCE or SDG&E on the other?

MR. MALCARNEY: Within California, we do not differentiate among the big three California utilities other than to try to balance our portfolio. We prefer not to be heavily weighted to one over the others.

We also focus on improving the geographic diversity of our portfolio by investing in projects outside California.

Pricing

MS. RIVERA: PG&E was not pushed into bankruptcy because it had too many debts or because its revenue is shrinking. It was pushed there by wildfires. To some extent, wildfires are an unknowable risk. To another extent, they are probably a direct effect of climate change and will be more likely in the future.

With that in mind, let's drill down into two types of risk: bankruptcy risk and wildfire risk.

Pascal Uttinger, starting with you, how do you price bankruptcy risk in a project financing?

MR. UTTINGER: Offtake credit risk is a major driver for pricing in any non-recourse project finance transaction. The probability of default by the offtaker, including as a result of a bankruptcy filing, is a key pricing metric. The higher the possibility of default, the lower the rating and the higher the price of the loan.

That said, if there is a foreseeable material risk of an offtaker bankruptcy, then lenders will simply not lend. There is no price at which a regulated bank would lend where the offtaker is expected to file for bankruptcy. As the rating falls, you would get the higher price to offset that risk, but a default would have to be unexpected to lend at all.

MS. RIVERA: Paul Pace, are there other considerations that you take into account when you are considering bankruptcy risk for a project?

MR. PACE: Yes, the regulatory environment in the state. There is not a huge difference in general among investment-grade utility offtake contracts. Whether the utility is an A- or BBB credit, we do not see much difference among utilities in terms of pricing and bankruptcy risk.

Another consideration in pricing is the all-in costs of borrowing under corporate revolvers. It would be odd to price inside of those spreads on a single-asset offtake contract that is entirely dependent on that single offtaker. You should not really price such a loan at a tighter spread than the spread on revolvers, but sometimes that happens.

Another key metric is where the utility's bonds are trading. If the bond market is saying that something is X basis points over Treasury yields and you swapped over LIBOR, you should probably be pricing at an equivalent spread to Treasury bonds.

All of that said, at the end of day, it is a competitive market in which something like a PG&E bankruptcy happens once every 20-plus years. I don't think the banks are that concerned about bankruptcy risk. They look at spreads on revolvers and bonds, and the spread in a project financing ends up wider or near the other spreads.

Developer Calculus

MS. RIVERA: Kevin Malcarney, as an asset owner that wants to finance his projects, you are probably concerned about bankruptcy risk, but for different reasons. Can you describe how Clearway looks at this risk, and do you look at bankruptcy risk differently when you are thinking about a construction or other contractor versus an offtaker?

MR. MALCARNEY: The big questions for Clearway are whether the project can continue to perform and generate revenue through the bankruptcy and how our credit agreements function in a bankruptcy situation.

An offtaker bankruptcy, as far as I know, is always an event of default under both the power purchase agreement and any financing agreement.

Some of the questions we have to ask are whether there is a risk of the agreements being rejected by the debtor, how soon after bankruptcy filing we can get a good read on the likelihood the contract will be rejected, whether our cash distributions will be trapped and, if so, how soon the cash will be released, and whether we can continue to service project debt and ongoing operating costs without injecting additional equity into the project.

We need to look at the total picture and determine whether the project will survive through the offtaker or contractor bankruptcy or whether the project itself may need to avail itself of the protections afforded by the bankruptcy code. Fortunately, we have not had to have any project file for bankruptcy.

Many power contracts with PG&E allow the utility to pass through the amounts the utility pays for electricity to the ratepayers. Rejecting those contracts would / continued page 20

IN OTHER NEWS

Utilities in California, Missouri and Indiana have received regulatory approval to do tax equity transactions as regulated utilities. The Northern Indiana Public Service Company received approvals in 2019 and 2020 for tax equity deals involving two wind farms. The Empire District Electric Co. in Missouri received regulatory approval in 2019. Liberty Utilities received approval from California in 2017.

Wisconsin Power and Light said that it has been driven into the tax equity market because the 100% depreciation bonus has put it in a net operating loss position through 2023. It expects to be unable to use tax credits from any new solar projects for even longer because it must work through tax credits in first-in-first-out order.

While it must ordinarily share the benefit from tax credits with its customers over the 30-year life of solar projects, it said this "normalization" does not apply to tax credits claimed by a partnership in which it is a partner. However, it said its customers will be better off because they will benefit immediately from the cash flow the utility will be distributed by the partnership without having to wait until it can use tax credits several years in the future. It said it will use the cash or expenses incurred as an offset to its normal utility cost of service when determining its revenue requirement for setting rates.

UTILITIES keep asking the IRS whether renewable energy projects they plan to own will be "public utility property."

The IRS confirmed in another private letter ruling made public in early August that a solar-plus-storage project that an unnamed utility plans to build, and a second such project that the utility plans to buy under a build-transfer agreement from a developer, will not be.

The ruling is Private Letter Ruling 202032002.

Utilities cannot claim investment tax credits and accelerated / continued page 21

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not have significantly increased the bankruptcy estate or the amount recoverable for wildfire victims, creditors and other stakeholders.

While the risk of rejection is always there until you get a confirmation order in place, it did not seem to make much sense that PG&E would reject those contracts.

As far as contractor bankruptcy goes, they do not always trigger an event of default under either the PPA or the financing, so that situation is a little different. If it is a material contractor, then we need to analyze whether the contractor is likely to survive the bankruptcy. If not, the issue is whether we can easily replace its services with some sort of temporary credit support that will not affect the non-recourse nature of the project under the financing agreement, but that would let the project survive through the bankruptcy and come out on the other side.

Inverse Condemnation

MS. RIVERA: Let's go back to the banks. How do you take into account wildfire risk? Do you look at the track records of utilities? The physical terrain where they are located? Paul Pace?

MR. PACE: That all comes into play. We look at where the project is located, who the utility is, and how vigorously the utility is taking steps to prevent its equipment from causing wildfires.

An issue is California inverse condemnation. Even if PG&E did all the right things, it is on the hook. There is no need to prove negligence to hold it accountable. This was problematic to say the least. That was one thing that was probably underestimated when we looked at PG&E.

We look at the spend that needs to go into preventative maintenance, and how utilities plans to cover the cost.

MS. RIVERA: Pascal Uttinger, how do you address wildfire risk?

MR. UTTINGER: I see two parts to this question.

There is a direct risk to the project itself. To assess that risk, we do standard project finance diligence, meaning we attempt to cover off wildfire risk as it would threaten a particular project. The lenders work with the independent engineer to make sure that there are sufficient fire-mitigation measures being taken. We look for any history of wildfires in the place where the project is located.

Then, separate from that type of diligence, we also make sure that the insurance package is adequate and includes business interruption insurance. If it is an existing project, lenders might run some cases based on what the project has encountered in the past with respect to fires and outages it has suffered because of them.

> Loans to projects with PG&E offtake contracts carry a 25- to 50-basis-point risk premium.

The second part is obviously the utility exposure to wildfire risk. For that, I think there is a differentiation between PG&E and the other two California investor-owned utilities. The PG&E service territory is far vaster and also covers more rural parts of central and northern California. Communities are expanding into areas that have vegetation that is more prone to fire risk.

I agree with Paul Pace that this risk was under appreciated in the past. There have been recent legislative and regulatory changes in California to mitigate the risk and make it more feasible for lenders to continue lending to California utilities and projects.

MS. RIVERA: Kevin Malcarney, how does Clearway look at wildfire risk? Do you use a higher hurdle rate for an asset that has this risk?

MR. MALCARNEY: The PG&E situation made everybody focus on inverse condemnation and wildfire mitigation strategies. From our point of view, risk includes the ability to manage wildfire risk and recovery liabilities. We take this into consideration when making investments.

I can't get into specifics about higher or lower returns since we view projects on an overall basis. It is important to note that the overall regulatory construct in California has improved with the passage of AB 1054, and the utilities are making significant investments and trying to change some of their strategies for mitigating wildfires and the negative effects.

People are really trying to manage that risk a lot more than they did in the past and are paying attention to it a lot more. This should help the industry overall.

MS. RIVERA: There are other risks. We have been focused on wildfires, but sea-level risks are an example. Are there any other climate-change-type issues that you think about when you look at projects in California?

MR. PACE: On an individual project level, we are more focused on climate-change issues, whether it be floods, projects that are built near shores or in areas that are prone to storms. The risks can be mitigated with insurance and the right amount of engineering.

The difference here is that the utility did not handle the climate-change issue, and that is what threw it into bankruptcy. The issue was not the location of any project.

On top of it, there is no way to underestimate the amount of tragedy in loss of life and property. With flooding, a rising sea level and similar issues, the utility is not going to cause the damage. The issue is climate change and how the utility manages it.

What we worry about most with all these things happening is the insurance market. Will insurance become prohibitively expensive on projects we would like to finance?

MS. RIVERA: You went exactly where we wanted to go. Kevin Malcarney, are you worried about what this does to the cost of insurance for renewable energy projects?

MR. MALCARNEY: We worry about the impact of legislative and regulatory responses to the environmental changes on insurance markets. You cannot de-risk everything. We try to stay on top of legislative and regulatory developments so that we can be in a position to respond to market changes and continue operating in a safe way.

AB 1054

MR. BERGER: The root cause of the PG&E bankruptcy was wildfires which are clearly a risk in California.

After PG&E filed last year, we heard that lenders not surprisingly stopped lending to projects with PG&E offtake contracts. Many lenders took a wait-and-see approach with the other California utilities.

There seemed to be a lot of hope that AB 1054 would further thaw the financing market. The new statute is already being put to use after the California Department */ continued page 22*

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depreciation on assets that are "public utility property" if they are forced by regulators to pass the value of the tax benefits to ratepayers more rapidly than under a "normalization" method of accounting. Congress wanted the tax benefits to act as an inducement for utilities to invest more, which it felt would only happen if utilities are able to keep part of the value.

Utilities already have a strong incentive to make investments that add to rate base in order to grow revenue.

Utility rates are usually set by determining the amount of revenue the utility needs to earn the regulated rate of return on its rate base, or invested capital, and then by working backwards to the rates it should charge to get to this projected revenue.

Assets used to supply electricity are "public utility property" if the rates at which the electricity is sold are regulated on a rate-of-return or cost-of-service basis.

The utility that asked for the latest ruling is in a state with a renewable portfolio target, meaning a requirement to deliver a certain percentage of its electricity from renewable energy.

The state increased the target and at the same time authorized the utility regulatory commission to let electric utilities charge competitive rates not tied to rate base or cost of service for electricity from any renewable energy facilities that a utility acquires or builds to comply with the state RPS target. The law also lets utilities charge whatever they agree to pay independent generators under power purchase agreements signed after competitive bid solicitations for electricity from facilities that they then acquire. Neither type of project can be put into rate base.

The ruling is the latest in a series of rulings the IRS has issued confirming that renewable energy projects whose electricity is sold at market-based rates are not public utility property. */ continued page 23*

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of Forestry and Fire Protection announced that the Kinkaid wildfire was caused by PG&E's electrical transmission lines. The Kinkaid fire was not addressed in the bankruptcy case; hence victims will not receive compensation from the wildfire victims trust created by the case. Instead, a separate wildfire fund created by AB 1054 will be the source of recovery.

Paul Pace, do AB 1054 and the state wildfire fund give you comfort to lend to projects with California utility contracts?

MR. PACE: Yes. The fact that PG&E must present plans for preventative maintenance and will be held responsible also help. It helps to have an extra set of eyes on the issue. Having more than $20 billion of loss coverage in front of you helps. We like having reserves in banking. The state fund is one more reserve to make sure the utilities remain healthy.

MR. UTTINGER: Project finance at its core tries to analyze risk and then make sure the right parties are bearing the appropriate risks for those parties and that the transaction overall is priced appropriately in light of the risk profile. What makes it challenging to do is there may be risks that are really hard to quantify or predict, such as wildfires causing a utility bankruptcy. Something like AB 1054 was needed given the inverse condemnation reality in California.

It was a thoughtful approach to address the risk. I think we will see that it is serving exactly its intended purpose, and lenders will start lending to projects with PG&E offtake contracts, which would probably have been extremely challenging to do if it were not for AB 1054 or something like it.

MR. BERGER: Kevin Malcarney, does AB 1054 play into Clearway's analysis?

MR. MALCARNEY: Yes, it does. I don't have a lot to add to what Paul and Pascal said. The Kincaid fire is a chance to see how well the fund works.

MR. BERGER: Is there anything else that you wish the California legislature or the California Public Utilities Commission would do to give developers and financing parties more comfort? Obviously eliminating inverse condemnation would be one step, but there seems little chance that will happen.

MR. UTTINGER: If things play out as expected, I don't think anything else is needed to bring liquidity back to the market.

The state renewable portfolio standard is so fundamental to California that if the state were to fall behind its goal, I think it would be addressed quickly. There is a collective will in the state not to let that happen.

MR. PACE: PG&E did not have any secured bonds before the bankruptcy. It does now.

It would have been nice to see the bonds issued unsecured. Making them secured bonds changed the dynamics in terms of what would happen if PPAs were to be rejected and what priority project-finance banks would have. This does not really involve the legislature. I am just pointing out one thing that has changed since pre-PG&E bankruptcy back in January 2019.

MR. MALCARNEY: Obviously first and foremost in everyone's mind is the protection of people and properties in California that are affected by wildfires. I don't think inverse condemnation is the right way to deal with that, but I don't have a better idea, so I guess until somebody comes up with something better . . . . Having the utilities improve their strategies for how to eliminate wildfires is moving us in the right direction.

CCA Contracts

MR. BERGER: If wildfires are the big unknown in terms of potential liability for a utility, one way to reduce that risk is not to contract with a utility.

California has a couple dozen community choice aggregators where cities and counties may buy electricity for residents in their communities. These CCAs do not deliver the electricity, but they use a local utility for that purpose. They do not have the same wildfire risk. However, because most of these CCAs are not rated, they do not have much of a balance sheet. Deals with CCA offtakes are harder to finance if they are financeable at all.

Are you concerned about bankruptcy and wildfire risk when doing a project with a CCA offtake contract?

MR. UTTINGER: From a portfolio theory, risk and risk-mitigation standpoint you should expect to see more lender interest in CCA offtake transactions. The CCA model is a completely different risk profile than the utility model, and there are some positives such as no wildfire risk, but there are also negatives.

CCAs are not exposed to wildfire risk because they do not have any material physical assets. That is both good and bad. If the regulatory and political support behind the CCA model were to wane, then their credit risk would increase much faster than for an investor-owned utility.

Where does all that net out? From our standpoint, we would expect CCAs to continue to play an increasingly significant role in the California market. Lenders should view this as allowing them to diversify their loan portfolios further, thereby reducing exposure to wildfire risk.

Lenders set concentration limits. Adding CCA offtake contracts to the mix allows banks to expand their lending in these markets by having new counterparties on the books. On a limited and appropriate basis, they should be able to be more active in these markets.

MR. PACE: At Key Bank, we have done deals with CCAs as the offtakers. This was accepted practice before the PG&E bankruptcy, and I think Pascal is right that a surprising consequence of this is that not having physical assets has become a positive when looking at CCA credit risk.

CCAs have their own set of challenges that are unrelated to wildfires, but having a CCA that has a slightly different business model and slightly different risk profile, but still has the same sort of bankruptcy risk protection in a lot of ways is something that has given them even better standing in the market than they had before.

Developers are evaluating how their credit agreements function if the offtakers go bankrupt.

MR. MALCARNEY: Our overall focus is on long-term power purchase agreements with creditworthy offtakers. The offtaker can be a CCA or a utility; we put the project through the same rigorous review before making an investment decision. Part of that analysis includes wildfire risk.

Bankruptcy Complications

MS. RIVERA: The big issue in the PG&E cases was whether PG&E would try to take advantage of being in bankruptcy to shed or renegotiate its PPAs. Various PPA counterparties organized and took steps to ensure that their contracts would not be rejected.

Can you talk briefly about what Clearway did in response to the PG&E bankruptcy filing? Were you focused just on the bankruptcy proceedings or were you doing other things outside of those proceedings? */ continued page 24*

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In cases where utilities raise tax equity through partnership-flip transactions, they put their investments as partners into rate base. (See, for example, "A utility tax equity filing" in this issue, "Utility partnership flips" in the June 2020 *NewsWire* and "Utility tax equity structures" in the December 2019 *NewsWire*.)

The IRS has stopped issuing private letter rulings as a labor-saving measure in areas where it thinks it has already made the law clear enough in a notice, revenue ruling or other published guidance. It will be interesting to see how many more times it is willing to repeat essentially the same advice in private letter rulings about public utility property.

THE PROPERTY TAX ASSESSMENT on a natural gas pipeline was more than 50% too high, an appeals court said in August.

Transwestern owns a 2,500-mile gas pipeline that crosses five states, including seven counties in Arizona.

The state assessed the part of the pipeline that passes through Arizona at $639.7 million in 2016 and $614.4 million in 2017, but then tried to increase the value to more than $700 million each year after Transwestern challenged the assessments.

After an eight-day trial and more than 1,000 pages of testimony, the Arizona tax court decided the proper assessment was $402.9 million in 2016 and $392.3 million in 2017.

The state appealed.

The appeals court focused on three issues.

One is the weighted average cost of capital used to discount the projected net revenue stream from use of the pipeline in Arizona. The Transwestern appraisal expert said to use discount rates of 10.2% in 2016 and 9.8% in 2017. The state's expert said 7.11% and 7.8% were more appropriate.

The Transwestern expert included a company-specific risk premium of 3% on grounds that the company has only 10 customers and limited liquidity */ continued page 25*

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MR. MALCARNEY: We approached it from a couple angles. We were in constant communication with our lenders either trying to negotiate forbearance agreements or waivers. We were in constant communication with our other contract counterparties, including PG&E.

PG&E does not have the right unilaterally to renegotiate a contract. It can either accept the contract in whole or reject it in whole. If it rejects the contract, it can try to renegotiate it.

That was not what happened in this case. There was not a lot of discussion about the PPAs themselves. We joined in the Federal Energy Regulatory Commission case with other yieldcos and independent power producers to try to establish who has the final say over rejection of PPAs.

We were also actively monitoring all the different legislative and regulatory proposals in California so that we could be in a position to respond quickly to whichever ones made it through the legislature and the CPUC.

We watched everything related to the bankruptcy in an effort to assess where we were going to come out on the other side. We figured out relatively early on that it did not make sense for PG&E to reject its renewable energy PPAs, even though many of them were out of the money.

While we were keeping our eye on the bankruptcy proceedings, we were also trying to renegotiate our way through our various project credit agreements, since the bankruptcy declaration was an automatic default under those agreements.

MR. BERGER: The bankers had to decide whether the bankruptcy filing was an actionable event of default under the financing documents for projects with contracts to sell power to PG&E. Paul Pace, what was Key Bank's general approach to this question?

MR. PACE: Our general approach was to work with our clients to understand what they were going to do. We believed that interests were aligned in this case. We tried to work constructively.

We did not allow cash distributions, just in case something went against us. We would not have wanted to let the cash get away. Other than that, we spent time doing the same analysis that Kevin Malcarney described.

We put together internal memos. We talked to our senior management team. We told them how things were going to play out. We had a thesis. We talked to our legal counsel to understand more ramifications. Our thesis was that everything would be fine in the end.

For developers, the third-party events of default are probably what keep them up at night because they are out of the developers' control.

MR. BERGER: Pascal Uttinger, how did MUFG respond to the bankruptcy filing?

MR. UTTINGER: MUFG took a similar approach. We also strived to take a view early in the process so that we could get conviction around our thesis, which was that there was no benefit to the stakeholders in the bankruptcy to start abrogating contracts and increase the unsecured liabilities of the bankruptcy estate.

Bankruptcy is an automatic event of default in project finance documents to protect the lender in case the unexpected happens. We took the same approach as Key of not allowing distributions until that uncertainty is removed.

At the same time, we also quickly realized that our interests are aligned with the sponsors. We wanted to take as evenhanded and light a touch as possible and still protect the bank's interests.

Do Differently?

MR. BERGER: Kevin Malcarney, what should developers do differently when negotiating project contracts, especially offtake contracts, having gone through this bankruptcy process?

MR. MALCARNEY: You can put a lot of words in a contract about what the bankruptcy of a contract offtaker means, but at the end of the day, you are largely at the mercy of the bankruptcy court and the debtor. Most of our projects are separately financed. Once you make an assessment as to whether it makes sense for the debtor to reject or assume the project PPAs, our focus quickly shifts to the financing agreement.

The lender's counsel often takes the most aggressive position with respect to when the event of default begins and ends.

An offtaker bankruptcy has often been an event of default without a defined cure period in the financing agreement. It could be helpful to clarify exactly when it begins. Is it the public notice that the debtor intends to file, which is the position that a lot of people took, or is it the actual filing that starts the event of default?

There is also uncertainty about when the default ends. Does it end upon assumption of the contract even if the bankruptcy case is still ongoing? Does it end with confirmation of the plan or filing of the emergence notice? There are some areas where it would be helpful to eliminate ambiguity or uncertainty around the process, which would allow companies like mine to allow for better planning of capital allocation decisions and decisions about changes to dividends.

I am not sure how much you can write into the PPA or loan agreement that will make a difference, but these agreements could be clearer about what happens after an offtaker event of default.

MR. BERGER: Pascal Uttinger and Paul Pace, what would you do differently the next time?

MR. UTTINGER: We feel good about how our process was handled, even though we saw an array of approaches being taken by other lenders. Some lenders quickly got their workout groups involved. Others pushed to change law firms to bring in workout counsel in reaction to the filing.

We did not take those more extreme approaches. There is nothing we would necessarily want to do differently the next time.

MR. PACE: We would not handle anything differently, but the bankruptcy court is a huge unknown and uncertainty, and I think you have to take each case on its own. You also have to look at each regulatory jurisdiction on its own.

Hopefully our approach of being deliberate about it, being smart about it, coming up with our thesis, and then working with our sponsors and hopefully having interests aligned is always going to be the right approach. ◎

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as a private company. He added another 1.8% in 2016 and 2% in 2017 as a "small-company risk premium." The court said neither factor justifies these premiums. It sent the case back to the tax court to determine the appropriate weighted average cost of capital.

Transwestern reduced the projected revenue stream by 39% to cover federal and state income taxes, even though Transwestern is not subject to entity-level income taxes. It is a wholly owned subsidiary of Energy Transfer Partners, which is a master limited partnership, or MLP. An MLP is a large partnership whose units are traded on a stock exchange or over-the-counter market.

The appeals court said it would not second guess the tax court, which allowed the subtraction.

The Arizona tax department conceded that the MLP partners would have to pay income taxes on the income. The appeals court said other states have allowed taxes to be deducted in this situation, citing 2019 and 2020 court decisions in Minnesota involving Enbridge Energy, a diversified energy company that owns oil and gas pipelines and is organized as a partnership.

The last issue is whether it is appropriate to reduce the valuation as Transwestern's expert did by 59% in 2016 and 60% in 2017 on grounds that the pipeline is economically obsolescent.

Transwestern said the drop in demand during the 2008-to-2009 recession, falling prices for natural gas and competition from green energy have made the pipeline less valuable.

The state said any economic obsolescence is already taken into account in depreciation, and the fact that Transwestern made an additional investment in a lateral to serve Phoenix undermines the claim of economic obsolescence.

The appeals court declined to overrule the tax court. It said poor */ continued page 27*

Pension Plans Pressured Over ESG Investments

by Marjorie M. Glover in New York, and Joseph Denker in Houston

A US Department of Labor proposal to bar retirement plan administrators from considering environmental, social and corporate governance (ESG) factors when choosing investments could have a significant effect on the renewable energy sector.

More than 1,500 comment letters were submitted by the July 30 comment deadline. The overwhelming majority were strongly opposed to the new regulation.

The regulation is expected to be reissued in final form by year end.

The results of the November elections are expected ultimately to affect whether the regulation is implemented.

Administrative Burden

Retirement plan fiduciaries have a duty under section 414 of ERISA to act prudently and solely in the interest of plan participants and beneficiaries. ERISA is a 1974 law that establishes minimum standards for private-sector pension plans.

The proposed regulation would prohibit plan fiduciaries from considering ESG factors, or investing in funds set up to make ESG investments, if the effect is to subordinate return or increase risk for the purpose of pursuing a non-financial goal.

It would require plan fiduciaries to consider other investment alternatives, document decisions where an ESG investment is chosen, and refrain from designating an ESG fund or fund pocket as the default investment where a plan participant does not choose an alternative.

If finalized in its proposed form, the additional due diligence, process and documentation requirements are expected to discourage retirement plan investments in ESG vehicles.

The potential impact on investment in renewable energy could be significant.

At the end of the first quarter of 2020, total US retirement plan assets exceeded $28 trillion. Assets invested in sustainable funds increased fourfold from 2018 to 2019. As more millennials and other generally social-conscious investors add to their retirement savings, interest in ESG investments is expected to increase exponentially.

Past Government Positions

The Department of Labor proposed the new regulation in late June.

President Trump directed the Department of Labor in Executive Order 13868 in April 2019 to review trends with respect to retirement plan investment in the energy sector.

The proposal follows on the heels of other recent government efforts related to ESG investments.

The Securities and Exchange Commission added ESG investments to a list of 2020 examination priorities. The SEC is interested in the accuracy and adequacy of disclosure by registered investment advisors marketing new or emerging investment (including ESG) strategies.

The Department of Labor stepped up its fiduciary enforcement efforts by sending letters in May to plan sponsors, asset managers and other plan fiduciaries requesting information on what factors plans consider when investing in ESG vehicles.

The government's view of ESG investments has changed from time to time, largely mirroring changes in the political landscape.

A US Department of Labor proposal could impede pension plan investments in renewable energy.

The Department of Labor issued its first interpretive guidance on economically targeted investments (ETIs) — which is the department's term for socially responsible investments or investments using ESG criteria — during the Clinton administration in 1994. The initial standards were in Interpretive Bulletin 94-01.

The initial guidance recognized that ETI investments were not inherently incompatible with ERISA and that, plan fiduciaries may use non-pecuniary factors as a deciding factor when choosing among competing investments that serve the plan's economic interests equally well. The "all-things-being-equal" or "tie-breaker" test has served as the cornerstone for retirement plan investments in ETIs and ESG for more than 25 years.

The Department of Labor scaled back the ESG guidance during the Bush administration in Interpretive Bulletin 2008-01 in 2008. It broadened the ESG guidance during the Obama administration in Interpretive Bulletin 2015-01 in 2015 after concluding that the 2008 guidance had unduly discouraged fiduciaries from considering ETIs and ESG factors.

After President Trump was elected, the department once again scaled back the ESG guidance by clarifying in Field Assistance Bulletin 2018-01 in 2018 that plan administrators should take into account as financial factors, when making investments, whether ESG issues present material risks or opportunities to company business plans.

Consistent with 2018 guidance, the proposed new regulation recognizes that certain factors such as a company's improper disposal of hazardous waste or dysfunctional corporate governance may present a pecuniary risk that may be considered. However, it would go further than the 2018 guidance by requiring that a plan fiduciary focus only on pecuniary factors and it would prohibit a plan fiduciary from sacrificing return or accepting additional risk by promoting a public policy, political or any other non-pecuniary goal. Although it would retain the "all-things-being-equal" or "tie-breaker" test in concept, the department said in June that it "expects that true ties rarely, if ever, occur," which would render the tie-breaker test effectively unavailing.

Blowback

The number of comments received about the proposed new regulation by the July 30 deadline set a near record for comments about Department of Labor initiatives.

The majority of comments were that there is no evidence that retirement plan fiduciaries are misusing ESG factors when considering what investments to make. */ continued page 27*

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economic conditions are a recognized source of economic obsolescence.

The Transwestern expert arrived at his economic obsolescence percentages by comparing Transwestern's current rate of return to its historic return and to the rates of returns of six other pipelines serving the same region.

The case is *Transwestern Pipeline Company v. Arizona Department of Revenue*. The court released its decision in August.

CARRIED INTERESTS in partnerships earn income that is harder to report as long-term capital gain.

The classic carried interest is one that entitles the holder to a share of the upside after an investor has reached a return threshold.

Section 1061 of the US tax code, enacted in late 2017, targeted individual investment fund managers whose income for managing funds is paid to them in their capacities as partners in the funds. Asset sales by the fund may produce long-term capital gains that are taxed at reduced rates if the assets have been held for more than a year. The character of the income as long-term capital gain normally passes through to the partners.

Critics charge that the income received in this manner by fund managers is essentially compensation that should be taxed at ordinary rates.

The bare language of section 1061 does not appear to cover the types of carried interests that project developers in the project finance market receive when a money partner is brought into a partnership to own a project.

The IRS confirmed this in 162 pages of proposed regulations that it issued in July to implement the new section.

The IRS said the section applies to partnerships that own the following types of "specified assets": securities, commodities, real estate held for rental or investment, cash, cash equivalents, options and */ continued page 29*

Pension Plans

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Diplomacy may have gone out of fashion in the current era. For example, one letter writer called the proposed regulation an "unprecedented, unnecessary, and dangerous reversal" of policy. Another said it is unnecessary, based on "a woefully incorrect understanding of investing knowledge and theory, an endangerment to the retirement security of Americans, internally inconsistent, applying an inadequate analysis of ERISA fiduciary law and a violation of federal cost-benefit regulations." Another said it is "out of step" with the best practices that asset managers and financial advisers currently use to integrate ESG considerations into their plans.

Others asked the department to move in the opposite direction by encouraging ESG to play a role in choosing investments. For example, the American Council on Renewable Energy (ACORE) letter said the following:

If the proposed rule had the effect of chilling or reducing ESG investment, it would harm American's global competitiveness by allowing foreign investors to earn comparatively higher rates of returns . . . . [T]he Department should modify the proposed rule to clarify that ERISA's fiduciary duties compel qualified investments professionals to consider ESG investment principles as economic considerations under generally accepted investment theories.

Some comment letters challenged the view that the new regulation would not impose additional burdens on plan administrators who choose to make ESG investments. The letters said the increased burdens associated with additional due diligence, revisions to investment policies, investment advisory and management agreements and other documentation have not b een considered.

The issue has become yet another source of partisan division in Washington.

Twenty-one members of the House Committee on Education and Labor submitted a letter calling the proposed rule "a solution in search of a problem" and urging the department to withdraw the proposal.

The Republican committee members said in a separate comment letter that "[u]nder ERISA, a . . . duty of loyalty prohibits [a pension plan fiduciary] from prioritizing political agendas or social policy preferences over the financial security of American workers."

Others want the department to extend the comment period. The AFL-CIO and other unions asked for an extension of 120 days to give workers more time to have their voices heard.

Some groups said they support the new regulation, citing the need for greater measures to ensure that retirement plan fiduciaries do not invest in ESG funds that charge unreasonably higher fees or place non-financial goals ahead of pension plan returns or safety.

Timetable

The new regulation will not become binding until it is reissued in final form.

Many believe that President Trump will try to reissue it as a final regulation by year end. It would be harder for any new administration to reverse a final regulation than one that is merely proposed if there is a change in administrations after the November elections. Any new administration would not take office until late January. ◎

Cap on Interest Deductions Explained

by Keith Martin, in Washington

The Internal Revenue Service filled in detail in July in 860 pages of new regulations about how the cap works on the interest expense that a company can deduct each year.

The cap has the potential to make borrowing more expensive.

It was part of tax reforms that the US adopted at the end of December 2017. The cap has been temporarily increased for 2019 and 2020 as an economic relief measure in response to COVID-19. (See "Coronavirus: Economic Relief Measures for Companies" in the April 2020 *NewsWire*.)

Interest on debt cannot be deducted to the extent a company's net interest expense exceeds 30% of its adjusted taxable income. The cap is 50% for tax years starting in 2019 and 2020, unless the company is a partnership, in which case the higher cap applies only in 2020.

A company's income for this purpose means income ignoring interest expense, interest income, NOLs and — only through 2021 — depreciation, amortization and depletion. Thus, the limit on interest deductions is less likely to come into play through 2021 than after (when the cap will be the cap percentage of a smaller number).

There was uncertainty about whether power companies can add back depreciation through 2021 to income for calculating the cap. The IRS said in 2018 that depreciation that is treated as a cost of producing "inventory" is not added back to income. The IRS takes the position that electricity is inventory.

However, the IRS backtracked in July. It is now allowing power companies and other manufacturers to add back depreciation and amortization.

A company can use its 2019 income tax to calculate its cap in 2020. Congress worried that companies will have to borrow to ride out COVID-19 while the economic lockdowns leave them with less income.

The limit is on net interest expense. Interest expense is first netted against any interest income for the year. The cap limits the deduction of what remains.

Any interest that cannot be deducted in a year can be carried forward indefinitely.

The limit on interest deductions does not apply to any business with average gross receipts of $25 million or less.

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derivatives contracts with respect to any of the foregoing, and interests in other partnerships that hold these types of assets.

In addition, the person receiving the carried interest must receive it in exchange for certain services that either it or an affiliate will provide to the partnership. The services are "raising or returning capital" or investing in or developing these types of specified assets. A person is considered to be "developing" specified assets if the fund represents to investors, lenders, regulators or other interested parties that the value, price or yield may be enhanced or increased because of the choices or actions of the partner receiving the carried interest.

If that is not enough, the section does not apply to carried interests received by corporations (but not S corporations, which remain covered).

If the partner holding the carried interest has both a "profits" interest and a "capital" interest, the section does not apply to gains to the extent they are attributable to the capital interest. Most partnership interests are both profits and capital interests. A profits interest entitles the partner to a share of ongoing partnership income. A capital interest entitles the partner to a share of the partnership assets when the partnership liquidates.

The carried interest is no longer covered by section 1061 after it is sold to a third party who has never provided services to the partnership itself or through an affiliate and does not plan to do so in the future.

If section 1061 applies, then two things happen.

First, the partnership must have held assets for more than three years before the share of gain on sale reported by the carried interest holder qualifies as long-term capital gain.

Second, any transfer of the carried interest to an affiliate triggers immediate tax to the carried interest holder on the unrealized gain in the partnership assets that have been held for three years or / continued page 31

Interest Deductions

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It does not apply to regulated public utilities. It is elective for real estate businesses.

Congress estimated that 95% of businesses will not be affected through 2021.

The limit is calculated at the partnership level where a project is owned by a partnership. Any interest that cannot be deducted by the partnership because of the limit is allocated to the partners and held by the partners for use solely to offset any future "excess" income they are allocated by the partnership.

There is no transition relief for existing debt. Interest on debt that was already in place when the cap was enacted in late 2017 is subject to the cap just like interest payments on new debt.

Interest

The IRS issued final regulations in July 2020 to implement the cap.

It proposed in 2018 to define interest payments that are subject to the cap more broadly than some in the market expected, but then narrowed the definition in July 2020.

Commitment fees on loans are considered interest for this purpose to the extent the financing is actually provided.

Debt issuance costs are not interest.

"Guaranteed payments" that a partnership makes to partners for use of capital are not considered interest, unless they are economically equivalent to interest. A guaranteed payment is an amount the partnership is required to pay a partner for use of capital the partner contributed or for services regardless of whether the partnership has income to cover the payment. The partnership deducts such payments, unlike normal cash distributions where there is no deduction at the partnership level. The IRS regulations include an example where a partnership is considering borrowing from a bank, but decides to have one of the partners make a capital contribution instead in exchange for guaranteed payments. In this case, the payments are treated as interest. They are interest if they are incurred for the use of funds for a "period of time" and are "substantially incurred in consideration of the time value of money."

Some tax counsel have speculated that preferred cash distributions to a tax equity partner could fall into this category, but the preferred cash distributions would have to be a debt by the partnership to the partner rather than simply a first use of cash to the extent there is cash to make the payment.

A fee paid by a US subsidiary to its foreign parent company to guarantee repayment of a bank loan to the subsidiary is subject to the cap as interest.

Prepaid rent in a sale-leaseback transaction is considered a loan by the lessee to the lessor that is worked off over the lease term. The imputed interest on such a loan may not be deductible by the lessor unless there is room within its cap.

Partnerships

Many projects in the project finance market are owned by partnerships.

The cap is applied at the partnership level.

The partnership calculates its income or loss for the year. The income or loss is allocated to the partners. In the process, the partnership must determine its cap on the amount of interest expense it can deduct. It determines that by first calculating its "adjusted taxable income" or what the IRS calls "ATI."

Its ATI is its taxable income calculated normally and then adjusted by backing out interest expense, interest income, NOLs and — only through 2021 — depreciation, amortization and depletion.

The cap on interest the partnership can deduct is 30% of ATI (50% in 2020) plus any interest income the partnership earned during the year.

The US caps the amount of interest that companies can deduct.

To the extent there is room within the cap to deduct all the interest the partnership incurred during a year, then interest deductions at the partnership level are simply reflected in the shares of partnership net income that are allocated to each partner.

If the partnership had room within its cap to deduct more interest, then the extra room is called "excess taxable income."

If the partnership does not have room within its cap to deduct all the interest it incurred, then the interest it could not deduct is called "excess interest expense."

The partnership must report to each partner at the end of each year the partner's share of ATI at the partnership level, the gross interest expense and gross interest income at the partnership level, and any excess taxable income (unused cap) or excess interest expense (interest that the partnership could not deduct because of the cap).

The calculations then move to the partner level.

First, each partner adjusts its "outside basis" in its partnership interest by its share of the ATI at the partnership level minus the gross partnership-level interest expense that it is allocated. For example, if its share of partnership ATI is \$50 and its share of partnership-level interest expense is \$20, then its outside basis goes up by \$30, even if the partnership has a cap that allows only \$15 of the \$20 in interest expense to be deducted when calculating partnership income.

Next, each partner must determine whether it can use any excess interest expense (interest that could not be deducted by the partnership due to the partnership-level cap).

It must jump through three hoops to do so.

First, it must not have run out of outside basis. If the partner has run out of outside basis, then use of the excess interest deduction is suspended.

"Outside basis" is a way of tracking what each partner put into the partnership and is allowed to take out. It is one of two metrics for doing this. (The other is called a "capital account.") A partner cannot deduct losses allocated to it by a partnership once it has run out of outside basis. Use of the losses is suspended until the partner has more outside basis. Two things give it more outside basis: being allocated income in the future by the partnership or making a capital contribution to the partnership.

Second, even if the partner has enough outside basis to use the excess interest expense allocated to it by the partnership, it must wait until it is allocated excess taxable income against which to use the excess interest expense. Basically, it can only deduct the extra interest as the partnership / *continued page 32*

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less. However, the carried interest can be transferred to a partnership with one or more affiliates without triggering tax.

OREGON lost another round in a long-running battle with the BC Hydro trading arm, Powerex, over whether electricity and gas that the company sells to customers in California, but that pass through Oregon, can be taxed in Oregon.

After losing an earlier court decision, the state tax department changed its rules. It then lost again in a case involving tax years 2011 through 2015. The earlier litigation involved tax years 2002 through 2004. (For earlier coverage, see "Electricity is tangible property" in the August 2016 *NewsWire*.)

Powerex is a British Columbia company. It buys and sells electricity in the wholesale market. It does not own any assets in Oregon or serve residential customers. The Oregon Public Utility Commission does not consider it a utility.

Oregon taxes companies doing business in the state on any income originating in Oregon. The state used a three-factor formula to determine how much income to assign to Oregon during the period 2002 through 2004: the same share as the fraction of a company's total property, employees and sales that are in the state, with extra weight given to the sales factor. By 2011 to 2015, the state had changed to a single factor: the share of total sales in the state.

Electricity is considered tangible personal property in Oregon.

Income from sales of tangible personal property is considered earned at the "ultimate destination" of the property rather than the delivery point under any contract between the buyer and seller. The state tax court determined that none of the sales during the period 2002 through 2004 were taxable in Oregon because the ultimate destination was outside the state, generally in California.

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Interest Deductions

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allocates it unused partnership-level cap in a future year.

Third, the partner must do its own cap calculation to determine whether there is room within its own cap to deduct the amount. The partner does this by calculating its own adjusted taxable income or ATI, but in so doing it ignores everything allocated to it by the partnership other than any allocation of "excess taxable income" (unused cap at the partnership level). For example, a partnership with $200 in ATI can deduct up to $60 in net interest expense (30% x $200). Suppose it is has only $30 in interest expense. It will have used only half of its cap for the year. The unused half of the cap translates into $100 in ATI. The $100 is "excess taxable income."

If a partner sells its entire partnership interest before it is able to deduct the excess interest deductions it was allocated by the partnership, then the un-deducted amount is added back to its outside basis immediately before the sale. This reduces its gain on sale.

Utilities and Real Estate

The regulated utilities made a trade with Congress. They gave up the ability to write off the full cost of new and used assets put in service during the year — called a 100% "depreciation bonus" — in exchange for being freed from the cap on interest deductions.

The trade applies to the extent a company is engaged in the business of furnishing electricity, water, sewage services, local gas or steam distribution or pipeline transportation of gas or steam where the rates at which these services are provided are established or approved by a federal, state or local government agency. The rates do not have to be set on a cost-of-service or rate-of-return basis. The IRS said rates are considered "established or approved" for this purpose by a company whose electricity is sold at negotiated rates if the company must file a "schedule of such rates with a regulatory body that has the power to approve, disapprove, alter the rates, or substitute a rate determined in an alternate manner."

Electric cooperatives are treated as regulated utilities for this purpose if their rates must be reviewed by "the governing or ratemaking body of an electric cooperative."

Real estate businesses can take the same trade. They do so by filing an election with the IRS.

Groups of corporations that join in filing a consolidated federal income tax return are treated as a single company.

This creates complications. Many utilities have a utility holding company that joins in filing a consolidated return with a regulated utility subsidiary. The group usually also has other companies engaged in non-regulated businesses.

Interest deductions are capped to the extent the interest relates to the non-regulated business. This requires calculation of the ATI of the non-regulated businesses and a determination on which side of the company the interest expense resides.

The IRS regulations treat money as fungible. Therefore, interest expense anywhere in the consolidated group must be allocated between the regulated and non-regulated parts of the group in the same ratio as the assets owned by each part. The group looks at its adjusted bases in the assets. The IRS felt this would be easier for companies to track than using the relative fair market values of the assets.

Depreciation for adjusting asset bases in equipment is calculated under the old depreciation rules immediately before MACRS depreciation was enacted in 1986. The original cost basis is used for land, buildings and other "inherently permanent structures" like gas pipelines or electric transmission lines, wind towers, and steel uprights and underground wires at utility-scale solar facilities. The basis is not reduced as buildings and other "inherently permanent structures" are depreciated.

Assets are ignored until they are placed in service. Thus, no interest is allocated to projects while they are still under construction.

The only interest expense that does not have to be allocated across all assets is interest on "qualified" nonrecourse debt. This is debt, in theory, that was borrowed on a nonrecourse basis secured solely by particular assets. It is not considered fungible. However, it is hard for most nonrecourse debt to qualify in practice.

All other deductions are allocated to the part of the business to which they are directly related. An example is property taxes.

Intercompany transactions between members of a consolidated group are ignored. Stock in a subsidiary that is also part of the consolidated group is not counted as an asset when allocating interest expense between the regulated and non-regulated parts of the group by asset basis.

If 90% or more of the company's tax basis in assets in a year is in either the regulated or non-regulated part of the business, then the company can treat all the interest that year as tied to the 90%-or-more side of the business.

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Infrastructure Projects

The IRS said in a revenue procedure in 2018 that public-private partnerships undertaking certain kinds of infrastructure projects can opt out of the interest cap.

Any such project opting out will be treated like a real estate business, which also has the option to opt out. Depreciation on any project that has opted out would have to be taken on a straight-line basis over a longer "class life" for the type of assets rather than the normal depreciation period. However, this would be required anyway to the extent the project is financed with tax-exempt bonds.

The project would have to jump through several hoops to qualify to opt out.

First, it would have to be a type of project that can be financed by issuing tax-exempt private activity bonds. Examples are hydroelectric power plants, power plants whose electricity remains within a two-county area or one city and one county, local district heating and cooling facilities, airports, roads, ports and high-speed intercity rail lines.

Second, the private company undertaking the project would have to have a contract with a government with a term longer than five years that requires it to build, manage or operate and maintain the project. The project must be made available for use by the general public.

Third, the assets must be owned by a government or, if they are privately owned, they cannot be used in a regulated utility business whose rates are regulated by a body like a state public utility commission or the Federal Energy Regulatory Commission on a cost-or-service or rate-of-return basis. However, the rates charged the general public for use of the assets must be subject to regulatory or contractual control by a government or to government approval.

The conditions for opting out are in Rev. Proc. 2018-59. ◎

In 2015, the Oregon tax department adopted a new sourcing ruling solely for "public utilities" that sourced income to the "contractually specified point of physical delivery." Thus, if electricity or gas changed hands at a hub in Oregon on its way to California, the state claimed the right to collect an income tax on the sale. Then after a 2018 audit, Oregon assessed taxes against Powerex back to 2011 after concluding that the electricity and gas trader is a public utility.

Curses, foiled again.

Powerex went back to court. It said it is not a public utility and the state cannot change its rules retroactively in this manner.

The court agreed that Powerex is not a public utility. It said it did not have to reach the question about retroactive tax law changes.

The case is *Powerex Corp. v. Department of Revenue*. The Oregon tax court released its decision in mid-July.

VIRGINIA told Walmart that it could not enter into one or more corporate power purchase agreements to buy electricity for its 188 stores in the state.

Before 1999, Virginia residents had to buy their electricity from the local utility. The state experimented with retail choice from 1999 to 2007 when retail customers could choose their electricity suppliers.

Since 2007, the local utility has been the sole authorized supplier, except in two situations. Large customers whose electricity needs exceed five megawatts a year and customers who want 100% renewable energy, but who are not given that option by the local utility, can contract with other suppliers.

The Virginia Corporation Commission has discretion to let nonresidential customers who can aggregate load to get above five megawatts also contract directly with another supplier. Walmart tried that approach. The commission turned down the request. It did so again on appeal in July. / continued page 35

DFC Window Opens for Domestic Loans

by Tracy Horton and Kenneth W. Hansen, in Washington

The US government is making available new loans to fund domestic private-sector projects that support the domestic industrial-base capabilities necessary to respond to the COVID-19 outbreak, including by bringing relevant manufacturing back to the United States.

The loans are being offered by the US International Development Finance Corporation (DFC).

The first loan planned under the program — a $765 million loan to Eastman Kodak to allow the company to make chemicals needed for anti-coronavirus medications — was put on hold while the government investigates charges of insider trading after stock options were granted to several Kodak executives shortly before the loan was announced and the stock jumped 1,000% following the loan announcement.

Background

The DFC was launched in January 2020 under authority granted in the BUILD Act of 2018 to replace the Overseas Private Investment Corporation and to administer what was the US Agency for International Development's development credit authority. (For more information, see "DFC Replaces OPIC" in the February 2020 *NewsWire*.)

The DFC's statutory purpose is to "mobilize and facilitate the participation of private sector capital and skills in the economic development of less developed countries."

President Trump authorized the DFC in an executive order on May 14, 2020 to make domestic loans pursuant to section 302 of the Defense Production Act of 1950 "that create, maintain, protect, expand, or restore domestic industrial base capabilities supporting the national response and recovery to the COVID-19 outbreak, or the resiliency of any relevant domestic supply chains."

The Defense Production Act is a Korean War-era statute that gives the US president broad powers to press US factories into service to support the war effort. The Trump directive is Executive Order 13922.

Loans made under the authority granted by the executive order will be funded through $1 billion appropriated to the Department of Defense under the CARES Act and will not count against DFC's $60 billion annual lending cap. The authority delegated under the executive order will expire on March 27, 2022, in accordance with title III of division B of the CARES Act.

On June 22, 2020, DFC and the US Department of Defense (DOD) entered into a memorandum of agreement detailing the joint administration of the first $100 million of DOD's CARES Act spending plan. DFC will originate, screen, underwrite and finance projects under the new loan program in consultation with DOD. Under the memorandum, DOD will bear all direct and indirect costs of the loan program.

Concurrently with the release of the memorandum, DFC issued a request for proposals for loans under the new program, a separate "Defense Production Act Loan Program Guide" and the form to use to apply for loans (DFC-014), all of which are available on the DFC website at https://www.dfc.gov/dpa.

The loan program guidelines and documents are effective immediately and without advance notice or a comment period due to "the urgent and compelling circumstance" of the COVID-19 outbreak and the time-limited nature of the program.

A US agency that makes loans to support overseas development is now starting to lend to some US manufacturers.

Adam Boehler, the DFC CEO, said the program will be administered by an approximately 15-person dedicated team within DFC that is walled off from the other DFC programs.

According to the request for proposals, Boehler, as CEO, will have sole discretion to select eligible projects, meaning that loans and projects will not require approval by the DFC board of directors.

DFC will accept proposals in response to the RFP until February 28, 2022. However, given the length of time the screening and underwriting process can take and the relatively short window DFC has to fund projects until March 27, 2022, interested parties are encouraged to submit relevant proposals as soon as possible.

Eligibility and Selection

The new loan program is focused on the following sectors: pharmaceutical, personal protective equipment, medical testing supply, airway management consumables, vaccine-related items and "relevant" material or technology.

Projects eligible for loans are private-sector projects in the United States that create, maintain, protect, expand or restore (including reshoring) the domestic response to and recovery from the COVID-19 outbreak or the resiliency of any relevant domestic supply chain.

Aside from obvious areas like health-care supply chains for medicines, masks and personal protective equipment, loans could also be made to fund data science innovations and supply chains for electronics, manufacturing, machine tools, industrial controls and raw materials.

The loan program guidelines say that DFC must determine, among other things, that "the loan supports the production or supply of an industrial resource, critical technology item, or material that is essential to the national defense [and that] without the loan, the US industry cannot reasonably be expected to provide the needed capacity, technological processes, or materials in a timely manner."

Any products associated with projects involving the manufacturing of pharmaceuticals or medical equipment must be certified by the US Food and Drug Administration in order to be eligible for the program.

Eligible projects must be sponsored by the private sector and be commercially viable with a demonstrated "reasonable assurance of repayment" of the loan. DFC cannot compete with private-sector banks and other private sources of financing. Sponsors must demonstrate that private financing is unavailable on reasonable terms, that the DFC loan is the best way to fill the financing gap for the project and that any additional funding required for the project will be available within a reasonable period of time.

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The two main Virginia electric utilities are Virginia Electric Power Company (VEPCO) and Appalachian Power (APCO). A hearing examiner concluded that letting Walmart go its own way on electricity would increase monthly bills for remaining VEPCO customers by 13¢ a month and for APCO customers by 5¢ a month.

The commission said Walmart must be arguing that it is in the public interest to have many customers pay a little more so that it can pay a lot less. It was not persuaded of the public interest.

After oral arguments in the appeal, but before a decision was announced, the state legislature enacted a new law setting up a pilot program in VEPCO service territory under which nonresidential customers who can aggregate to five megawatts can buy electricity from independent suppliers. The pilot program took effect on July 1, 2020 and is subject to review by the Virginia Corporation Commission in 2022.

The case before the commission was called *Wal-Mart Stores East, LP v. State Corporation Commission*. The commission released its decision on July 9.

GOVERNMENT PAYMENTS to induce a company to relocate had to be reported as taxable income, a US appeals court said in late July.

Brokertec moved 720 employees to New Jersey in 2002 after its offices in the World Trade Center were destroyed on September 11, 2001.

New Jersey had adopted an economic incentive program to induce companies to relocate to the state and bring jobs or expand existing facilities in a manner that adds to employment.

Companies had to apply to the state Economic Development Authority. Grants were discretionary. Applicants had to promise to maintain a minimum

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DFC Loans

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The RFP selection criteria and application are also heavily focused on the qualifications of the project's management team. Factors such as the management team's previous track record with similar projects, experience in the relevant sectors, depth, credibility and cohesiveness, and experience servicing debt obligations, managing institutional capital and meeting reporting requirements will be considered.

The loan application requires character- and fitness-type certifications, such as, that the borrower and owners of the borrower are not debarred by any federal department or agency, are not involved in any bankruptcy, and are not delinquent on and, in the last seven years, have not defaulted on a federal loan that caused a loss to the government.

The borrower must also certify that the borrower (if an individual) and any individual owning 20% or more of the equity of the borrower are not subject to criminal charges, currently incarcerated, or on probation or parole, and, within the last five years have not been convicted of, pleaded guilty or nolo contendere to, or been placed in a pre-trial diversion, parole or probation with respect to any felony.

Loan Terms

The loan may be structured as a project finance loan to a special-purpose vehicle or as a corporate loan.

The loan may be used for the acquisition, development, construction, ownership or operation of facilities or equipment, working capital or other costs associated with an approved project.

The loan terms will be determined on a case-by-case basis, although some general guidelines are available. According to the RFP, loan amounts may range from $10 million to $500+ million dollars. (This latter amount appears to assume that there will be an increase or extension of the memorandum of agreement between DFC and DOD.)

Loans will generally not exceed 80% of project costs.

The loan program materials do not provide an offered interest rate, but by statute the interest rate must be determined by the US Treasury to be reasonable, considering the average yield on outstanding obligations of the United States with maturities comparable to the loan. The maximum maturity date will take into account the useful economic life of the project, but in no event will exceed 25 years.

Any loan will be secured by a collateral package that may include, among other things, a pledge of shares of the borrower, liens or mortgages on assets, guarantees from creditworthy individuals or companies, irrevocable standby letters of credit or a debt service reserve account.

The loan program materials do not specify the amount of origination fees and other charges due to DFC, but the program guidelines do indicate that fees and other charges may be collected.

Other Considerations

The loan program materials indicate that applications that make it through the initial screening will be subject to environmental, credit and legal due diligence and that applicants may be asked to retain third-party consulting services, such as environmental and social consultants, an independent engineer and an insurance consultant. Costs for such consultants can be included in financed project costs. The project will be submitted for approval by the DFC CEO after the completion of due diligence.

In addition to the uncertainty around loan terms and fees noted earlier, other aspects of the program are not yet clear and may delay closing of the initial loans. For example, DFC has not indicated what environmental and social standards and review process DFC will apply to the loans. The loan terms may be documented by a commitment letter and will in any event be finalized in a finance agreement.

Despite the open issues, the program is an important opportunity for projects in the relevant sectors to fill financing gaps while working with a sophisticated and knowledgeable lending institution. ◎

California Update

by Jim Berger, in Los Angeles

A California Public Utilities Commission decision in late June should lead to wider adoption of micro-grids in the state, at least in the service territories of the three large investor-owned utilities.

The three utilities must take various actions promptly to accelerate micro-grid and resiliency projects to minimize the effects of future wildfires. The affected utilities are Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric.

State law defines a micro-grid as an interconnected system of electricity customers with energy resources, including distributed resources like rooftop solar, energy storage, demand-response tools, or other analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary.

The micro-grid must be able to act as a single, controllable entity and to connect to, disconnect from or run in parallel with, larger sections of the electrical grid, or else be managed and isolated to withstand disturbances.

Due to the increasing destructiveness and frequency of wildfires in California, the CPUC has authorized the three large utilities to turn off electricity to protect public safety. Public safety shut-offs were used extensively in 2019, especially by Pacific Gas and Electric. The power was shut off for as long as several days at a time, affecting several million people in California.

Micro-grids allow customers to have electricity when the grid is not operating.

The latest CPUC action should accelerate installation of micro-grids by reducing cost and speeding the approval process. It is CPUC rulemaking 19-09-009.

The decision is a response to Senate Bill 1339, which became law in 2018. The bill requires the CPUC to facilitate installation of micro-grids to serve customers of utilities with more than 100,000 customers.

The bill set a deadline of December 1, 2020 for the CPUC to publish micro-grid service standards to help developers meet permitting requirements, reduce other barriers for micro-grid deployment and set utility rates and tariffs that will support micro-grids.

The three investor-owned utilities must now do three things to accelerate interconnection resiliency projects.

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number of employees at the new location for a certain period of time. There were no restrictions on how money would be used.

The state made payments over time that were a fixed percentage of state income taxes withheld from wages on company employees at the new location.

The percentage varied from 30% to 80% depending on whether the company was in a targeted industry or investing in a location where the state felt a greater need to bring jobs.

The state would not start making payments until a project was completed and the company had begun paying wages. The state income taxes withheld on wages had to exceed the amount of the grant so that the jobs would generate more revenue than they cost.

Two Brokertec subsidiaries that relocated to New Jersey received a total of $170 million in payments over 10 years. The IRS said tax should have been paid on the payments, but did not catch the issue on audit until the last four years of the period the company was receiving payments. During that period, the subsidiaries received a total of $56 million in payments.

Section 118 of the US tax code at the time spared corporations from having to report government payments as taxable income that are an inducement to the company to do something without adding to the company's wealth. An example is where a town pays the cost for a freight railroad whose trains block traffic to put the tracks on an overpass.

A US appeals court said the payments in the case had to be reported as income because they supplement income. They reimbursed the subsidiaries for part of their wages costs, thereby giving them more income.

The court said Brokertec might have avoided tax under section 118 if the state had calculated the payments as a percentage of invested capital.

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California

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First, they must adopt standardized, pre-approved approaches for interconnecting micro-grids that deliver energy services during grid outages. They must do this by informally consulting with industry to develop a basic set of designs to use as quickly as possible, and then they must formally engage at technical meetings to seek feedback and finalize templates. The CPUC gave the utilities only 10 days for the informal consulting.

The projects contemplated for these standardized systems are relatively small, generally less than 10 kilowatts for storage and less than 30 kilowatts for solar.

California is taking steps to promote wider adoption of micro-grids.

Second, they must simplify their processes for inspecting and approving proposed new micro-grids and make the processes more transparent. The goal is to reduce delays caused by utility inspections. The utilities must provide technical criteria that will determine whether a field inspection is necessary and, when necessary, in what circumstances videos, photos or a virtual inspection will suffice.

Finally, the utilities must prioritize interconnection of resiliency projects for key locations, facilities and customers. To do this, the utilities must add more staff and improve websites so that applications will be processed more quickly.

Cap and Trade

A federal district court in California in July dismissed a lawsuit by the Trump administration aimed at shutting down California's cap-and-trade program.

The lawsuit initially targeted the link between California's cap-and-trade program with Quebec's cap-and-trade program. California and Quebec carbon allowances have been tradeable in either market since 2014.

Late in the litigation, the federal government tried to broaden the scope of its challenge to target the California "Global Warming Solutions Act," a 2006 law that requires reductions in greenhouse gas emissions in the state.

The court did not allow the government to do so, leaving the lawsuit focused solely on the link between the California and Quebec programs.

The Trump administration argues that by linking its program with Quebec, California violated three clauses in the US constitution — the treaty clause, compact clause and foreign commerce clause — and a foreign affairs doctrine that leaves the conduct of foreign affairs to the federal government.

The court had previously granted summary judgment in favor of California on the claims related to the treaty clause and compact clause. The federal government had previously dropped its claim under the foreign commerce clause. The court said the foreign affairs doctrine does not bar a US state and Canadian province from linking their carbon allowance trading programs.

The case is called *United States v. California*.

There are at least two main effects from the decision.

First, participants in the California cap-and-trade program will continue to benefit from the linkage with the Quebec program. The benefits include a wider market for carbon allowances, reduced administrative and operating costs, and lower overall emissions reduction costs for covered entities that are subject to the emissions limits.

Second, and perhaps more importantly from a macro perspective, is that the decision is a victory for California in the multi-front war between the federal government and California. The Trump administration has attacked multiple California environmental and climate-related initiatives in the courts and by regulation.

Connected to this is the possibility that other jurisdictions could also link their programs. States have shown a growing interest in such linkage in the face of inaction on climate change at the federal level. They may see the California-Quebec linkage as a feasible path for reducing their own emissions, especially smaller states that may not be viable markets on their own. In fact, the Trump administration argued that other states may try to enter into similar arrangements if the linkage is allowed to stand.

The California cap-and-trade program sets a statewide limit on 85% of California's greenhouse gas emissions. The program uses auctions to put a price on greenhouse gas pollution, thereby incentivizing investment in cleaner technology.

Each year, the California Air Resources Board, or CARB, sets a "budget" for how many tons of greenhouse gases can be emitted by covered entities. Covered entities include major greenhouse gas emitters, such as power plants, refineries and other oil and gas facilities and certain factories, that emit more than 25,000 metric tons of CO2-equivalent per year and fuel distributors.

CARB then issues allowances equal to the budget. Some of the allowances are given to the covered entities while others can be purchased at auction or in a secondary market. Entities can also buy offset credits.

At the end of each compliance period, each covered entity must have enough allowances to cover all of its greenhouse gas emissions. Each entity determines whether it is more economical to buy allowances or to invest in equipment to reduce its greenhouse gas emissions.

The program is supposed to lead to lower and lower greenhouse gas emissions as the budget set by CARB decreases each year by approximately 3%. However, in the most recent auction, only about one third of the credits were sold as a result of dampened economic activity due to the coronavirus pandemic. The regulators may need to re-think the budgets going forward.

The program has also produced more than $13 billion of revenue to the state of California, which has been used to reduce greenhouse gas emissions by investing in more than 428,000 projects. The investments include affordable housing, renewable energy, public transportation, zero-emissions vehicles, environmental restoration, sustainable agriculture and recycling.

Electric Trucks

CARB moved in June to require all diesel trucks and vans sold in California to be zero-emission vehicles by 2045. The new rule is called the "advanced clean trucks regulation."

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Congress changed section 118 in late 2017. The section now says that payments by governments and civic groups to corporations must be reported as income unless they are made by the government or civic group in the capacity as a shareholder.

The case is *Commissioner v. Brokertec Holdings, Inc*.

AMERICAN INDIANS are subject to US income taxes on gravel mined on the reservation, a US appeals court said in August.

The decision is the latest in a saga that has been playing out in both the US Tax Court and a federal district court and in which the two courts came to opposite conclusions.

The appeals court decision should now put the matter to rest.

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

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

The Tax Court concluded that neither treaty spares her from having to pay income taxes on the gravel sales. The district court said the treaties protect her from having to pay taxes on the income.

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

However, the tribes are still considered sovereign nations.

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

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California

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It will have three main effects (in addition to the large expected environmental and health benefits).

First, it will dramatically change the transportation market in California. It will force manufacturers to innovate and transition to new products. While it is costly for manufacturers to produce a special product for one market, they will undoubtedly do so due to the size of the California market, which is the largest truck market in the United States. The new rule should also lead to construction of a large number of electric vehicle charging stations and hydrogen fueling stations.

The state is also pushing truck fleet owners to move to electric vehicles.

Second, the transition to zero-emissions vehicles could create a new source of electricity demand. The final environmental assessment reviewed in connection with the rule forecasts a temporary increase in energy demand from construction and modification of equipment. It also foresees an incremental permanent increase in energy demand as zero-emissions vehicles make up a larger share of the transportation sector. Some new vehicles will be battery powered and others will be hydrogen powered.

Finally, what California does could have a multiplier effect as other jurisdictions adopt similar rules. A group of 15 states and the District of Columbia recently announced that they agreed to develop an action plan to require all medium- and heavy-duty vehicles to be zero emissions by 2050, with a target of 30% by 2030. The coalition states account for 40% of all US truck sales.

The CARB rule has two main pieces. First, it requires manufacturers of medium- and heavy-duty vehicles to show an increasing percentage of California sales of zero emission vehicles over time.

Second, large employers (including retailers and manufacturers) and fleet owners will be required to report information about their existing fleet operations. The information will be used by CARB to develop future strategies to cause more fleets to switch to zero-emission trucks.

The zero-emissions vehicle sales requirement applies to manufacturers that certify incomplete chassis or complete vehicles of greater than 8,500 pounds in gross vehicle weight and sell at least 500 vehicles in California annually. The smallest trucks to which the rule applies are trucks like the Ford F-250 and Ram 2500. It covers everything larger up to highway tractor-trailers.

The number of zero-emissions trucks that a manufacturer must reach as a percentage of total sales each year varies by vehicle class. It starts between 5% and 9% for model year 2024 and increases over time.

Manufacturers can also earn credits beginning with the 2021 model year. The credits allow manufacturers flexibility by selling more of one weight category and less of another. The credits can be banked and traded.

CARB is considering issuing two complementary regulations. One would set tight new limits on nitrogen oxide emissions, which are a major component of smog. The other would require larger fleets in the state to transition to electric trucks year over year.

Trucks represent only two million of the 30 million registered vehicles in California, but they are responsible for 70% of smog-causing pollution and 80% of soot. The new rule is expected to lower related premature deaths by 1,000 a year. ◎

Surety Bonds Compared to LCs

by Paul Weber and Connie Gao in New York, and Rob Marsh in London

Parties to project finance transactions are sometimes asked to accept surety bonds as security in place of letters of credit. There are key differences between the two instruments.

A letter of credit is a promise by a bank to advance up to a certain amount of money to one deal party if the other party defaults.

A surety bond is a guarantee in which a third party — often an insurance company — agrees to assume a defaulting party's financial obligations.

Although letters of credit and surety bonds are similar in function, there are legal differences that could affect a beneficiary's ability to obtain full and prompt payment on its claim.

Parties to commercial transactions have for years argued over the forms of security providing credit support to their deals. Beneficiaries, known as "obligees," prefer letters of credit over surety bonds because letters of credit generally are easier to collect upon, usually merely by presentation of certain documentation. Payment under surety bonds is usually a more drawn-out process and involves a greater risk of litigation on the underlying commercial transaction and any other defenses that may be available to the surety company.

The key distinctions between letters of credit and surety bonds arise from the business concepts and legal principles underpinning these forms of security.

Letters of Credit

A letter of credit is a written instrument that is traditionally issued by a bank. It authorizes a party to draw up to a certain amount of money under terms outlined by the instrument.

Three main parties are involved in a letter of credit transaction, namely, the issuer (bank), the customer of the issuer (applicant) and the beneficiary (obligee).

Usually, the letter of credit is accompanied by a promissory note from the applicant to the beneficiary and the applicant's agreement to reimburse the issuer upon its payment to the beneficiary. Parties select either the Uniform Commercial Code of the relevant jurisdiction, or "UCC," or the Uniform Customs and Practice for Documentary */ continued page 42*

IN OTHER NEWS

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

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

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

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

After losing in the Tax Court, she appealed the decision to a US appeals court while still waiting for the case to play out fully in the district court. The appeals court said it would not comment on the district court case because that case is still headed to trial. The district gave its view of the law in response to pre-trial motions and said a trial is needed to establish the share of Ms. Perkins' income in 2010 that is attributable to gravel sales.

The appeals court agreed with the government. It rejected the argument that any exemption available under the treaties to the Seneca Nation must also extend to individual members of the tribe. It said, "American Indian nations are treated differently from individual members."

The case is *Perkins v. Commissioner*.

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Surety Bonds

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Credits, or "UCP," issued by the International Chamber of Commerce to govern their letter of credit.

Two types of letters of credit are frequently used in commercial transactions: documentary letters of credit and standby letters of credit. A documentary letter of credit, which is usually governed by the UCC, is one in which the beneficiary must present specified documents to the issuer in order to draw funds from the letter of credit. Documentary letters of credit are primarily used as direct payment devices to facilitate sales-of-goods transactions. The typical documents that a seller of goods (the beneficiary) must produce in order to draw from the letter of credit include a bill of lading, commercial invoice, certificate of insurance covering transport or import-export documentation.

In a standby letter of credit, the issuer must honor the letter of credit after it receives a statement (usually in the form of a properly completed draw certificate) from the beneficiary that the other party to the underlying contract is in default under the terms of the contract or that the conditions to a draw have otherwise been satisfied. Standby letters of credit are the prevalent security instruments supporting obligations under construction contracts for thinly-capitalized construction companies, special-purpose project companies or owners, power offtakers with shaky credit ratings or any other entity that may need some credit support for its obligations.

Surety Bonds

Surety bonds are forms of guarantees. Under a surety or guaranty, a third party becomes liable upon the default of the principal, who is the debtor or guaranteed party.

Surety bonds can be payment bonds or performance bonds and involve the following three parties: a surety (the entity that assures payment or performance of the contract between the principal and the beneficiary), a principal (the entity who has the obligation to pay or perform) and an obligee (the beneficiary, or entity that is owed the obligation).

A suretyship is different from more common forms of insurance because sureties can seek repayment from principals, but insurers normally cannot seek reimbursement from those they insure and, instead, rely on payment of premiums across a portfolio of surety bonds for reimbursement coverage.

Key Distinctions

All letters of credit operate under the doctrine of independent contracts, which says that the issuing bank's obligation to honor or pay upon a properly presented draft is independent of the underlying contract or commercial relationship between the account party and the beneficiary presenting the draft.

Accordingly, the issuer is required to pay on the letter of credit regardless of whether the underlying contract has been properly performed by the account party or whether the account party has defenses to due performance. However, the issuer need not honor a draft under a documentary letter of credit if the documents or the transaction itself are fraudulent.

There are key differences between surety bonds and letters of credit.

Because letters of credit are independent from the underlying transactions, they are often more attractive to beneficiaries because there is no need to prove a breach of the underlying contract or the extent to which the beneficiary suffered damages. Further, traditional defenses and claims in contract law do not apply to letter-of-credit transactions because a letter of credit is governed by its own set of legal principles. Thus, from the point of view of a beneficiary, letters of credit are enforceable against an issuer regardless of the bankruptcy of the applicant.

Unlike a letter of credit, a surety bond attaches to the underlying contract and thus must be interpreted consistently with the underlying contract. The surety bond operates like a guaranty where a guarantor's obligation is secondary. This means that the surety's obligation does not mature until the principal obligor defaults on the underlying contract. In contrast, the obligation of an issuer in a letter-of-credit transaction is primary.

An obligee may see surety bonds as less desirable because they are not demand instruments like letters of credit. They involve a "claim adjustment process" in which the surety investigates the underlying default. This slows down the reimbursement process. Sureties will deny claims they believe are without merit.

At the same time, surety bonds, like other financial guarantees, are attractive to principals because they do not appear on a corporation's balance sheet, and their use does not diminish a company's line of credit. In addition, surety bonds are generally cheaper to procure and maintain and may not require posting of collateral to the surety by the principal obligor.

Making Sureties Work Like LCs

Because of these advantages, some sponsors are pressing certain obligees, including offtakers under power purchase agreements and virtual PPAs and interconnection agreement counterparties, to accept a surety bond over a letter of credit in order to facilitate a particular transaction.

The key to successfully persuading these counterparties to accept a surety bond is to craft the surety bond to minimize the disadvantages of a surety bond compared to a letter of credit.

One way to minimize the disadvantages of surety bonds is to draft the terms of the surety bond so that they provide protections to the beneficiary that are similar to those contained in a letter of credit. Since a traditional surety bond is subject to the surety's defense that no default of the underlying agreement has occurred, the obligee could change the payment trigger on the bond from one relating to the occurrence of an event of default to simply one triggered by the due presentation of a proper notice of default, notice of payment or other agreed-upon documentation.

Further, because the surety enjoys many of the same defenses that are available to a principal, the obligee should negotiate for language in the surety bond that waives the surety's ability to assert these defenses. Typical provisions should state that the surety's obligations are absolute and / continued page 44

IN OTHER NEWS

A TAX PLANNING STRATEGY is not a trade secret, a US appeals court said in late July.

TLS Management and Marketing Services in Puerto Rico runs a tax planning business to help clients minimize federal and Puerto Rican taxes.

Ricky Rodriguez-Toledo worked for it initially as a subcontractor starting in March 2012 and then as an employee starting in September 2012. He left in early 2015 and formed a rival tax planning service called ASG Accounting Solutions Group and took two former clients of TLS with him.

His contract while acting as a subcontractor had a non-disclosure clause. When he became an employee, he signed a confidentiality and non-disclosure agreement.

TLS sued him for misuse of trade secrets and breach of the two agreements.

TLS won in federal district court on both claims.

The appeals court overturned the decision. It said TLS has not proven its tax planning strategy is a trade secret since the strategy is based on publicly-available information, and the non-disclosure agreements were so broad as to be unenforceable. They would basically bar Rodriguez-Toledo from ever competing against TLS.

The tax strategy was a way for US companies to reduce income taxes on any part of their operations that could be outsourced to Puerto Rico to 4%.

For example, a US company might outsource its marketing function to a new TLC "division" and take a membership interest in the division and shares in TLS. It would run its marketing costs through TLS, deducting them in the US. TLS would pay the marketing profit back as a dividend to the US company. TLS has been granted a 4% income tax rate in Puerto Rico under Act 73 of 2008 and Act 20 of 2012. The dividend back to the US company would not be taxed in Puerto Rico if, by then, the US company had formed a / continued page 45

Surety Bonds

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unconditional irrespective of any circumstance whatsoever that might constitute a legal or equitable discharge or defense of a surety and include an express waiver by the surety of such defenses. Courts have generally held that these broad waivers are enforceable.

Transactions Governed by English Law

Standby letters of credit were first developed in the United States because US banks were prohibited from issuing guarantees.

Outside of the US, it is common to use an on-demand instrument, in similar circumstances, as a form of quasi-security to secure the obligations of a party to a contract. In practice, these English law-governed quasi–security instruments are labelled as a "bond" or "guarantee."

Irrespective of the title of the document, the instrument should be clear whether it creates primary ("autonomous") or secondary ("accessory") obligations. Disputes over whether these documents create primary or secondary obligations frequently lead to litigation or arbitration.

Standby letters of credit are more common than documentary LCs in project finance transactions.

In general, security instruments that impose autonomous obligations are often labelled on-demand bonds or guarantees, first-demand bonds or guarantees, demand bonds or guarantees or standby letters of credit.

Security instruments that impose accessory obligations tend to be called simply guarantees, default bonds or surety bonds.

An on-demand bond or guarantee will usually stipulate what documents have to be presented to the issuer in order to receive payment. The beneficiary need only issue a demand in accordance with the terms of the instrument and present the required documents. Unlike a conditional bond, there is no requirement to establish breach and quantum of loss. An on-demand bond operates independently of performance or non-performance of the underlying contract terms (hence, it is "autonomous"). These instruments operate like standby letters of credit by creating an autonomous payment obligation essentially in the nature of a standby letter of credit rather than a guarantee of a third party's performance.

Under a classic (as opposed to an on-demand) guarantee, the guarantor guarantees the performance of another party under an underlying contract and is a secondary obligor that has available to it all the defenses available to the primary obligor. In addition, the classic guarantor can often rely on modifications made to the underlying agreement after issuance of the guarantee to refuse payment on the basis that the risk it initially agreed to take has been changed. Also, the guarantor may require that the primary obligor's default be proven by the guaranteed party.

On-demand instruments often provide that they are payable upon presentation of a written demand and certain documents in a specified form. The instrument must state that the bank's undertaking to pay is irrevocable, unconditional and is a primary obligation. The bank must expressly waive all defenses related to the transaction in connection with which the bond is given or against the party against whose default the bond is meant to offer protection.

Despite the name, English-law standby letters of credit have more in common with on-demand instruments than with letters of credit. They enable the beneficiary to obtain payment from the issuer of the standby credit when the other contracting party has failed or is alleged to have failed to perform the contract.

In view of the apparent near equivalence of the two instruments, what determines the choice of one instrument over the other in an English law transaction?

The two key factors seem to be practice and location. The fact that US banks may only issue letters of credit has clearly led to the prevalence of standby letters of credit in international transactions involving American banks and in sectors where their use is the norm. In addition, standby letters of credit tend to be more widely used in connection with long-term contracts, such as project finance loans, and projects involving multilateral agencies. They are also found in oil and gas projects in the Middle East. On the other hand, in UK domestic construction and infrastructure projects, bonds and guarantees prevail.

There is a third factor. Calling on a bond should result in swift payment and receipt by the beneficiary. However, English courts in recent years have seen a number of cases concerning the proper interpretation of these security instruments. The attention given by the English courts to bonds and guarantees in recent years may also steer parties toward a standby letter of credit over an on-demand instrument.

Of paramount importance are clarity and certainty — and caution. Whatever instrument is chosen, the wording proposed may well have been used previously and, therefore, be regarded as "tried and tested." A precedent form is only tried and tested to the extent it has been analyzed by a court and not found to be wanting. It is important to understand its provisions fully. The key question to ask is whether the wording clearly describes the obligations of the parties and prescribes the desired outcomes for all of the relevant fact patterns. ◎

Puerto Rican subsidiary to own the TLS shares. If it needed the money back before then, the money would be advanced as a no-interest loan.

The Puerto Rican Trade Secrets Act defines trade secret, in part, as information that "has a present or a potential independent financial value or that provides a business advantage, insofar as such information is not common knowledge or readily accessible through proper means . . . ."

The court said TLS failed to prove that the information on which the strategy was based was not common knowledge or readily accessible. Testimony at trial suggested this was a common tax arbitrage strategy used by such companies as Microsoft and Apple, not only in Puerto Rico but also in the US Virgin Islands.

The case is *TLS Management and Marketing Services v. Ricky Rodriguez-Toledo*.

NEW SLEEP AID. TaxAct advertises on its website a new recording of a person reading the US tax code. The website claims that reading it on your own would take 19 days. The recording is called "Tax Code Coma" and is supposed to help listeners fall into a deep sleep. The group is so confident it works as advertised that the recording lasts only a little over 19 minutes.

— contributed by Keith Martin in Washington

Floating Solar

by Marissa Leigh Alcala and Pablo Calderon, in Washington

Floating solar — also known as floatovoltaics — is a small but growing segment in the solar energy industry.

More than 1,600 megawatts of solar projects were reported to be floating in waters around the world as of 2019, less than 1% of total global solar installations. Before 2014, only three floating solar installations were reported to have been installed worldwide, each with an output under one megawatt. At the end of 2014, global installed capacity had increased to 10 megawatts. The most significant leap in growth to date was between 2016 and 2017, when installed capacity of floating solar increased by 676% on a year-over-year basis.

A 2019 report by Wood Mackenzie forecasts demand for floating solar to grow by an average of 22% year-over-year from 2019 through 2024.

Floating solar has the greatest appeal in areas where land is scarce. Locating a solar installation on water can save on real estate costs, while leaving valuable real estate available for agriculture, residential, industrial or other purposes. Floating solar can also increase megawatts installed closer to electricity consumers. This could be particularly relevant in countries where the alternative might be to put ground-mounted solar projects in less populated areas that have high insolation but that lack adequate transmission infrastructure.

Floating solar may have additional operational benefits. While studies to-date are not conclusive, floating solar installations have documented increased efficiency and energy yield when compared to ground-mount or rooftop solar. The efficiency and energy production benefits are linked to a decrease in the temperature of panels, which results from the ambient water temperature contributing to more effective panel cooling. Whether or not this outcome is achieved depends in part on each project's design, as well as environmental factors at the project site.

Environmental benefits of floating solar have also caught attention. By covering a body of water, a floating solar installation can help reduce evaporation, limiting the effect of oxygen loss in the water during hot seasons. The reduction in evaporation is particularly relevant for floating solar installations on reservoirs. Reports indicate that floating solar installations may have positive effects for fauna and can slow the growth of algae by limiting the amount of light that reaches below the water's surface. As with efficiency, these potential benefits will vary based on site-specific factors and will form part of the analysis of any potential floating solar project site at the early development stage.

Diligence on any project must take into account not only traditional insolation data, but also data about the body of water, including depth measurements, evaluation of the bottom surface and high and low water levels throughout the year, the impact of wind on the water surface, flora and fauna within the body of water, and other environmental metrics and impacts. Many bodies of water have varying points of depth, and water depths may also vary over the course of the year. Reservoirs, in particular, may periodically dry up.

There is great variety in anchoring technologies and floating structures. The nature of the body of water and the percentage of the water surface to be covered may require different approaches to anchoring and floating. Three main structures are most widely used for flotation — pontoons, single floats (one float per module) and multi-floats (an array of modules per float). Innovation continues; new technologies are steadily being introduced, and what is in use and under development today may change over time.

Capital expenses for installation tend to be higher than for ground-mounted or rooftop installations. There are additional electronic and structural balance-of-system costs and higher labor costs than for projects on land.

Floating solar arrays are usually mounted on the floating structure on land and then dragged into the body of water.

Comparisons of operation and maintenance expenses between floating and ground-mounted or rooftop solar are not yet conclusive. When it comes to cleaning, floating solar may have an advantage over ground-mounted systems with less dust and dirt accumulation, although bird droppings may be a bigger issue in some areas. Inland floating solar installations can also use the body of water on which they are installed as a source of water for panel cleaning.

A majority of floating solar development has been on artificial bodies of water such as reservoirs, dams, irrigation and storage ponds. Floating solar can be co-located with existing hydroelectric projects or installed on bodies of water that have gathered in waste areas from prior industrial activities. Most of these artificial bodies of water are already close to roads and transmission lines. Inland natural bodies of water, such as ponds, can also be used.

Offshore development is currently only a small segment of the growing floating solar industry, despite the potential. There are examples of offshore floating solar development in Belgium, the Maldives, the Netherlands, Singapore and the United Arab Emirates, but the offshore installations have generally been much smaller than their inland floating counterparts. Offshore floating solar brings additional challenges, including the potential for saltwater corrosion, greater wear-and-tear from regular wave movement and a need for stronger anchoring. Sheltered seawater locations may mitigate some of these additional challenges, which will be greatest in open-sea locations.

Floating solar is expected to grow 22% a year over the next five years.

In June 2020, DNV GL launched a joint industry project with 14 industry participants, primarily based in Europe and the United States, to develop a set of recommended practices for floating solar projects.

This joint industry project will focus on five key topics: site-condition assessments, energy-yield forecasts, mooring-and-anchoring systems, floating structures, and permitting and environmental impacts. The goal is to come up with guidelines that can be applied to all floating solar projects regardless of technology and design. A draft document is expected at the end of 2020, with publication of the verified recommended practices currently scheduled for the first quarter of 2021.

No single technology or design is the clear market leader today. The technologies and designs will have to reach scale before the cost can decline.

Asia

China has more than 100 cities with populations of more than one million inhabitants. Not surprisingly, China is currently the country with the largest floating solar installations.

China has set ambitious renewable energy targets. As of 2019, 38.3% of the country's electricity came from renewables. Cumulative solar installed capacity was 208,000 megawatts at the start of 2020. Floating solar accounted for less than 1% of the total.

Of the top 20 reported operating floating solar projects in the world by size at the end of 2019, 12 were in China with four of those installations 100 megawatts or larger. Of the remaining eight top-20 floating solar projects, the largest was 47.5 megawatts (Vietnam) while the other seven ranged from 17 megawatts to 7.55 megawatts (in France, Japan, Netherlands, Taiwan and Thailand).

A majority of the floating solar projects in China are on collapsed coal mines where water has pooled in highly toxic unusable lakes.

Land is at least as scarce in Japan as in China, if not more so. Japanese multinational electronics manufacturer Kyocera started developing floating solar projects in 2014.

One of the largest Japanese floating solar power plants is on the Yamakura Dam reservoir in Ichihara, Chiba prefecture. The Yamakura Dam project opened in March 2018 and has an installed capacity of 13.744 megawatts. Kyocera developed and built the plant. The project is owned by the Chiba Prefecture Public Business Agency. All of the energy generated is sold to local electric utility, the Tokyo Electric Power Company.

The South Korean Ministry of Commerce, Industry and Energy announced plans in 2019 to build the world's largest floating solar power plant on Lake Saemangeum, on the west coast of Korea. At the time of the announcement the project was expected to require $3.9 billion of private capital. Original plans were for the 2,100 megawatts project to start construction in the second half of 2020 following regulatory review processes, including an environmental impact evaluation.

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Floating Solar

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In Taiwan, Google became one of the first companies to enter into a power purchase agreement under the 2017 Taiwan Electricity Act, which allows non-utility companies to purchase renewable energy directly. Until 2017, only utilities could buy renewable energy directly. The 10-megawatt project in Tainan City that will supply power to Google will be installed by Taiwanese energy developer New Green Power on fishing ponds. This project will experiment with a new floating solar design using panels that are hoisted just above the surface, increasing fishing yields for fishermen in the area. When completed, the project will be connected to the regional power grid. Taiwan is also home to a 7.674-megawatt floating solar project that started operating in 2018.

A $3.9 billion floating solar project is under development in Korea.

India issued several tenders in the past two years for solar electricity from floating projects. In 2018, the Solar Energy Corporation of India (SECI), a government agency, invited expressions of interest to build 10,000 megawatts of floating solar over a three-year period. The specific project tenders issued by SECI to date all appear to be below 20 megawatts.

The United Arab Emirates has set a goal of turning Dubai into a global green energy center by 2050. In 2019, the Dubai Municipality and Dubai Electricity and Water Authority issued a request for proposals from consultants to study, develop and construct floating solar installations in the Arabian Gulf. Dubai wants 75% of its electricity to come from clean energy by 2050. To support that target, the government plans to build a large "solar lake" in the emirate. The first floating solar project began energy production in early 2020 in Abu Dhabi as an open-sea installation of 80 kilowatts off the small resort island of Nurai. The UAE has a significant number of artificial islands where land is at a particularly high premium. The higher costs of open-sea floating solar may be easier to justify in this region than in other parts of the world. The Nurai project is expected to be studied closely as a test for other open-sea installations.

Europe

Floating solar in Europe is being built on a much smaller scale than in Asia. France and the Netherlands have recently made small-utility scale installations.

France had the largest floating solar project in Europe — a 17-megawatt floating solar project in Piolenc, France — when the project went into service in October 2019. A 30-megawatt floating solar project planned for Lac de la Madone, on two bodies of water at a former gravel pit, recently received local approvals to move forward after a 230-kilowatt test project was previously installed.

In the Netherlands, BayWa r.e., together with its Dutch partner GroenLeven, successfully built its third floating solar park in a record time of just six weeks. The Sekdoorn project in the Netherlands, near the town of Zwolle, has a total capacity of 14.5 megawatts. That was topped by what is currently reported to be the largest floating solar project in Europe, the 27-megawatt Bomhofsplas project on a sandpit lake in Zwolle, which started construction in February 2020 and was built by BayWa r.e. in seven weeks. A sale of the Bomhofsplas project to a Dutch consortium was reported in July 2020. Prior to the Bomhofsplas project coming on line, the Netherlands had already added 25 megawatts of installed floating solar capacity in less than one year.

The Netherlands also has a pilot offshore floating solar installation. At initial installation in 2019, the pilot project was 8.5 kilowatts. In January 2020, it doubled to 17 kilowatts. More modules are expected to be added in 2020. Oceans of Energy, the developer, hopes to install floating offshore solar in tandem with offshore wind in the Netherlands.

United States

Floating solar has not gotten the same traction to date in the United States as in Asia and Europe. Land is not as scarce near population centers and transmission lines. As a result, greater concern is shown over the lack of long-term data to show how floating panels will perform and be maintained over the span of decades, or how arrays could affect water quality and the natural habitats where they are installed over extended periods of time.

In 2008, Far Niente, a California winery, installed a 477-kilowatt floating solar system in Napa Valley, an area where land is particularly expensive. The project is over a water containment area used for irrigation. Installing a solar array on water, Far Niente kept its land dedicated to growing vines, a more profitable use for the winery. The solar array is connected to the power grid.

More than 10 years after Far Niente, a 4.4-megawatt Hydrelio floating solar project was completed in Sayerville, New Jersey at the end of 2019. The project was developed by Ciel & Terre, one of the world's largest suppliers of floating solar energy systems, in collaboration with Solar Renewable Energy and RETTEW. It appears to be the largest floating solar project currently in North America.

A National Renewable Energy Laboratory report in December 2019 said that floating solar has the potential to supply up to 10% of electricity in the United States. The report estimated that there are 24,000 artificial lakes, ponds and reservoirs that could host floating solar panels throughout the continental United States. It found the greatest potential for floating solar installations in parts of the US where both solar energy and agriculture may be competing for the same land. NREL estimated approximately 2.1 million hectares of land could be saved for agricultural or other uses if solar panels were installed on water instead of on the ground. NREL reviewed land value, evaporation rates and insolation data to identify areas in the continental United States that could be prime locations for floating solar.

Floating solar development in the United States is hampered by the lack of established precedent for issuing permits for floating solar installations. This makes estimating development costs and timelines more difficult. ◎

Environmental Update

The Trump administration weakened a major climate-change regulation in August by eliminating the obligation that oil and gas companies detect and repair methane leaks.

The head of the US Environmental Protection Agency, Andrew Wheeler, announced that the agency had completed the process of lifting an Obama-era methane regulation.

EPA estimates that the rule change will generate roughly $100 million a year through 2030 in economic savings. If the rule had stayed in place, it could require companies to repair and retrofit thousands of older existing oil and gas wells that are a source of significant ongoing leaks.

The rule change will allow the release of about 850,000 tons of methane into the atmosphere over the same period.

Methane is at least 30 times more potent than carbon dioxide as a heat-trapping gas.

Wheeler cited EPA data showing that leaks from domestic oil and gas wells have remained steady over the past decade, even while production has increased.

Newer studies indicate that methane emissions from drilling sites in the United States are more extensive than the agency's statistics, with methane levels climbing steadily nationwide.

Exxon, Shell, BP and other major companies had urged the Trump administration to keep the controls in place.

Those companies have invested millions of dollars to promote natural gas as a cleaner option than coal in the nation's power plants since natural gas produces about half as much carbon dioxide when burned. Unrestricted leaks of methane could undermine that message.

The Trump administration relieved oil and gas companies from an obligation to detect and repair methane leaks.

Flood Risk

Twice as many properties in the United States may be susceptible to flooding than previously thought.

New calculations by the First Street Foundation, a non-profit research group, that take into account sea-level rise, rainfall and flooding along smaller creeks not mapped by the federal government suggest that 14.6 million properties are at risk from a 100-year flood, not the 8.7 million properties shown on federal government flood maps.

A 100-year flood is one with a 1% chance of striking in any given year.

The First Street Foundation created its flood model using federal elevation and rainfall data and coastal flooding estimates from hurricanes. The foundation then checked its results against a national database of flood claims and historic flood paths.

US government flood maps managed by the Federal Emergency Management Agency guide developers in terms of where and how to build and whether flood insurance is appropriate, and guide lenders in determining whether the flood risk is too great to lend.

If correct, the new data suggest that developers, banks, insurers, homeowners and government officials have been making decisions with information that understates risk.

Nationwide Permits

The US Supreme Court reinstated most uses of a nationwide permit, called NWP 12, that, among other things, allows pipeline and utility trenching and construction activity in or adjacent to wetlands and other waters regulated under the Clean Water Act.

Pipeline and transmission-line developers need permission from the US Army Corps of Engineers before they can build in or disturb such wetlands or waters.

The court allowed developers to rely again on the NWP 12 permit as such permission nationwide in a one-paragraph unsigned order in July.

A federal district court in Montana had blocked reliance on the permit earlier in the year in connection with construction of the Keystone XL oil pipeline. The district court action had frozen construction at sites across the country and not just on the Keystone XL pipeline.

The Clean Water Act regulates construction and development activities near wetlands and other regulated waters. Section 404 of the act requires a permit before dredged or fill material may be discharged into any waters of the United States.

While some projects require site-specific permitting, the Clean Water Act allows the use of nationally applicable "general permits" for routine activities under certain circumstances.

NWP 12 is one of 52 general permits that the US Army Corps has issued under Clean Water Act section 404 that cover different categories of activities that are similar in nature, will cause only minimal adverse environmental effects when performed separately and will have only minimal cumulative adverse effect on the environment.

A national Army Corps permit that makes it easier to do construction near wetlands has been restored.

NWP 12 is a general permit that authorizes discharges associated with the construction, maintenance, repair and removal of oil and gas pipelines, electric transmission and collection lines, and telephone, cable TV and internet cables.

The Supreme Court order did not lift the injunction against use of the NWP 12 permit for the Keystone XL pipeline. That project remains in limbo until the Supreme Court decides whether to hear a case involving the pipeline. The court said that if it decides not to hear the case, the injunction delaying construction will be lifted. If it decides to hear the case, then whether the injunction will be lifted will turn on whatever decision the court reaches in the case.

The debate around the NWP 12 permit has focused on whether the US Army Corps failed to assess, in conjunction with other agencies, the cumulative impacts of the permit on endangered species before it reauthorized the permit in 2017.

By law, the Army Corps must review all nationwide permits every five years. The district court found that it failed to do the interagency consultation required under the Endangered Species Act before renewing NWP 12 in 2017. The district court later narrowed the scope of its injunction to block only construction of new oil and gas pipelines, but the matter was already on appeal.

The NWP program offers a streamlined permitting process for projects that qualify, which are those that will have only minor impacts on regulated waters. Specifically, NWP 12 authorizes discharges that result in the loss of up to half an acre of waters of the US. Discharges causing loss of less than a tenth of an acre qualify for self-certification without the need to notify the Army Corps.

Where a site-specific permit is required, the permitting process can take much longer.

NWP 12 is widely used by the utility industry. The ongoing litigation should be monitored until the Army Corps completes its statutory review process. Questions will remain about the viability of NWP 12 until the Army Corps completes this process.

There is a risk of future litigation to challenge the viability of NWP 12 more generally or / continued page 52

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even the viability of other nationwide permits where the Army Corps failed to perform the required review and interagency consultation.

All of the current nationwide Army Corps permits expire in 2022 when they come up for another five-year review. The Army Corps could start that review process soon as a way forward.

In the meantime, the Army Corps is proposing numerous changes to the its nationwide permit program for dredge-and-fill activity to speed regulatory approval of projects.

Among the proposals issued by the Army Corps in early August is the elimination of a 300-linear foot limit for losses of stream bed, the division of NWP 12 into three separate permits, and the creation of a new permit for water reuse and reclamation facilities.

"We are proposing these modifications to simplify and clarify the NWPs, reduce burdens on the regulated public, and continue to comply with the statutory requirement that these NWPs authorize only activities with no more than minimal individual and cumulative adverse environmental effects," the Corps said.

The Corps said it is proposing to divide NWP 12 into three separate nationwide permits that address differences in how different linear projects are constructed, the substances they convey, and the different standards and best management practices that help ensure that nationwide permits authorize only those activities that have no more than minimal adverse environmental effects.

The new NWP 12 would authorize only oil and natural gas pipeline activities. A proposed NWP C would authorize electric utility line and telecommunications activities, and a proposed NWP D would authorize other utility line activities that convey other substances, such as potable water, sewage, wastewater, stormwater, brine or industrial products that are not petrochemicals.

The Army Corps said it wants to remove electric utility and telecommunications lines and pipelines and mains that convey stormwater and sewage from NWP 12 because of "the differences in the relative amounts of ground disturbance and other related activities, including impacts to wetlands and other waters."

The proposal will be open to public comment upon publication.

Dominion Energy and Duke Energy announced in July that they were canceling the Atlantic Coast pipeline that would have shipped natural gas from West Virginia to North Carolina and Virginia. They said the decision by the Montana federal court to enjoin the use of NWP 12 was the last straw for the 600-mile pipeline.

— contributed by Andrew Skroback in New York