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Tax Equity Snapshot

Five prominent renewable energy developers spoke at the CLEANPOWER 2021 conference in early June about the current state of the US tax equity market. Many developers struggled during 2020 to find tax equity, even though market volume reached $17 to $18 billion, up from $12 to $13 billion in 2019.

Tax equity is a key tool for financing US renewable energy projects. The US government offers tax credits and accelerated depreciation as an inducement to build new renewable energy facilities, but few developers can use these benefits directly. Tax equity is a form of financing against the tax benefits.

The panelists are Meghan Schultz, senior vice president for finance and capital markets at Invenergy, James Marshall, CFO of AES Clean Energy, Andrew Nourafshan, managing director for structured finance at Cypress Creek Renewables, Steve Ryder, executive vice president and CFO of Clearway Energy Group, and Vishal Kapadia, senior vice president and chief commercial officer of Ørsted Onshore. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Still Challenging?

MR. MARTIN: Meghan Schultz, have conditions in the tax equity market improved since last year?

MS. SCHULTZ: We saw constraints in the tax equity market last year as banks braced for the uncertain impacts of COVID. The COVID impacts are easing this year, but there are still constraints in the market, especially as it relates to investment tax credit deals. / continued page 2

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RENEWABLE ENERGY PROJECTS that are considered under construction this year for tax purposes may not be able to claim tax credits at the higher rates that President Biden is proposing.

Developers should probably wait before starting construction of any additional projects.

A project is considered under construction for tax purposes once at least 5% of the total project cost has been incurred or once "physical work of a significant nature" starts at the site or at a factory on equipment for the project.

The US Treasury released a "green book" at the end of May with the details behind the Biden tax proposals. / continued page 3

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MR. MARTIN: How do you feel those constraints?

MS. SCHULTZ: There is a limited universe of tax equity investors. When you are marketing a transaction, some banks say they are only doing production tax credit deals. You hardly ever hear anyone say it is only doing ITC deals. Banks may only have insight into tax capacity in the current year. When you start to talk about a project that will need tax equity financing in 2022 or 2023 and that may be starting construction now, the banks are uncertain about whether they can commit. There were projects last year for which it took longer to secure tax equity or where we had fewer potential investors than we had originally anticipated.

MR. MARTIN: The ITC is what is claimed in the solar market. Because the investment tax credit is claimed entirely in the year the project is put in service, it puts more strain on tax capacity.

James Marshall, did AES Clean Energy have trouble last year raising tax equity and has the market improved this year?

MR. MARSHALL: We try to get ahead of the curve and lock up commitments for the following year to the extent possible in Q2 or Q3 of each year. We were in a good shape going into 2020. We closed all the tax equity we had anticipated.

For a good project pipeline, when you have a good relationship with your tax equity investors, the repeat business helps.

We have had a number of outreach opportunities that have come across our transom for 2021. There are a few investors looking to place additional 2021 capacity because of what happened in February in Texas. We are in the middle of placing 2022 tax equity and are feeling quite good about it.

MR. MARTIN: So you have tax equity investors approaching you trying to find 2021 projects in which to invest tax equity to replace Texas projects?

MR. MARSHALL: That's correct. We have had at least two or three approach us in the last few months.

MR. MARTIN: These are people who found themselves short because of the five-day cold snap in Texas?

MR. MARSHALL: I don't think they are explicitly saying that. My assumption is that they had some other transactions lined up that may not be so palatable any more, and they are indicating in some cases that they have meaningful capacity remaining for 2021.

MR. MARTIN: Andrew Nourafshan with Cypress Creek Renewables, was it hard to find tax equity last year, and is this year better?

MR. NOURAFSHAN: Last year was challenging. We certainly saw a slowdown, whether due to concerns about tax appetite or just needing to understand the broader economic picture before making commitments. It wasn't terribly disruptive to our ultimate execution plan, but Meghan Schultz was spot on in her assessment.

A difficult tax equity market last year created created a backlog of projects this year.

The difficulty raising tax equity last year has created a backlog of projects that got pushed from last year into this year. That has made it more difficult to start talking about 2022 and 2023 today with the added backlog of some really well-baked projects queued up for financing.

We have definitely seen a pickup in investor interest and ability to do deals this year, but there is also greater competition for scarce tax capacity because of this backlog in deals.

MR. MARTIN: Are you financing with the major players or are you having to reach out well beyond the mainstream investors to find tax equity?

MR. NOURAFSHAN: It is a bit of both. We are always speaking with the usual suspects, and then Cypress historically has had a lot of other tax equity relationships that we continue to maintain.

MR. MARTIN: Steve Ryder, Clearway has a big pipeline of deals. How was last year? How does this year look by comparison?

MR. RYDER: We align more with what AES is doing. We have been lining up tax equity for projects hitting COD in 2022 or 2023. To Meghan's point, I think it is easier to find tax equity for wind than for solar, but it depends ultimately on the technology, the location and the sponsor.

You have a group of top-level sponsors on this call that have generally good, reputable pipelines, strong track records of execution, good relationships with the power purchasers, equipment vendors and construction contractors, and probably good post-closing sophistication, as well. The tax equity that is available tends to migrate to those sponsors.

I suspect it is still hard for smaller companies and new entrants to get the attention of the tax equity market this year.

MR. MARTIN: So this panel is not the most challenged group of sponsors.

Vishal Kapadia, the trade press is full of stories about Ørsted Onshore financing new projects, often in Texas. How was the market last year? How does it compare this year?

MR. KAPADIA: I think the market conditions worked to our advantage. There has always been a haves and have-nots dynamic to the market. If you are a strategic with a global relationship with the large financial institutions, as we are, then you are in a much better position than if you are a fund-backed developer. This dynamic has been exacerbated by recent events like COVID and the Texas cold snap.

That said, unlocking ITC capacity has been more difficult for just about everybody.

It is more important to marry either broader relationship elements or, if you have the flexibility to do so, PTC wind transactions as part of a portfolio.

COVID earnings uncertainty was an overhang for much of last year. Things are in a much better place than they were last year.

MR. MARTIN: Have you seen any pause in Texas?

MR. KAPADIA: Not really. There is certainly more reticence and a need to look twice at the sponsor, the offtake story and the location, and people are spending more time underwriting the underlying elements of the project, but for us it is more of a delay as opposed to any issues in terms of unlocking the capital.

MR. MARTIN: Is the challenge with unlocking ITC tax equity solely uncertainty about tax capacity this year? Is it the fact that the entire tax benefit is claimed in one year, rather than spread over 10 years as with PTC transactions, or is it more than that?

MR. KAPADIA: It is the one-year nature of */ continued page 4*

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The administration is proposing to restore production tax credits and the investment tax credit to their full levels for projects on which construction starts after this year. The credits would remain at the full amount — 2.5¢ a kilowatt hour plus inflation for wind production tax credits and a 30% investment tax credit for solar — for projects on which construction starts during the period 2022 through 2026 before phasing down over the following five years.

Biden is facing a complicated puzzle in the Senate as he tries to advance his clean energy agenda. Everything must be folded into a large infrastructure bill.

Talks between Biden and Senator Shelley Moore Capito (R-West Virginia) in an effort to reach agreement on a bipartisan bill ended in early June after failing to produce an agreement.

A separate group of 10 Senators, including Mitt Romney (R-Utah) and Joe Manchin (D-West Virginia), said on June 10 that it had reached agreement on its own bipartisan plan, but many details appeared still to be determined as the *NewsWire* went to press.

It is unclear whether Democrats have the votes to put through a plan on their own. Joe Manchin continues to insist that he wants a bipartisan bill. The Democrats cannot afford to lose a single vote in the Senate if they plan to act alone.

Clean energy has not been part of any Republican offers in the bipartisan talks.

There is a danger of the Democrats losing the momentum they had last spring when Biden first proposed a $2.3 trillion infrastructure plan.

Another complication is a ruling by the Senate parliamentarian in early June that made clear the Democrats have only one more "budget reconciliation" card to play this year to put through bills by a majority vote in the Senate (rather than the 60 votes in the 100-member Senate that are required to pass bills in the face of Republican filibusters).

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the ITC and difficulty of forecasting tax capacity beyond any given year.

Tax Law Uncertainty

MR. MARTIN: Going back to Meghan Schultz, are you seeing any slowdown in financings this year due to uncertainty about where the tax law will land?

MS. SCHULTZ: No. It is an incredibly busy year on the solar side. We are focused on projects that are expected to be placed in service in 2022 and 2023. Similarly, the wind side is very busy for projects that we expect to complete in the next couple years. We are financing projects based on current law. There are always negotiations around what happens if the tax laws change, but that is something that we are used to seeing in deal papers.

MR. MARTIN: Is there anyone among the five of you who sees a slowdown in financings because of tax-law uncertainty?

MR. MARSHALL: We have encountered a little bit, not so much for 2021 projects as for projects that require forecasting tax capacity in two or three years.

MR. MARTIN: Steve Ryder, the Senate Finance Committee voted in late May to increase the tax credit amounts for projects placed in service after 2022. Of course, this may never go anywhere — it is too early to tell whether there will be an infrastructure bill this year — but do you see anyone slowing development or construction in anticipation of a bump up in the tax credit amounts after 2022?

MR. RYDER: I remember someone telling me that, in the development business, time is never your friend.

I think developers are more inclined to get the project done rather than delay things for something that might not happen. People have signed power purchase agreements with guaranteed commercial operation dates. They may have guaranteed delivery dates for wind turbines and solar panels. For those reasons, we are not seeing any slowdown.

MR. MARTIN: What happens if the bill is enacted later this year and then you have a year to wait before the increased tax credit amounts take effect?

MR. RYDER: We will have to face that prospect at the time. Things seem too uncertain at the moment in Washington to act based on what the Biden administration or others have proposed.

MR. MARTIN: Does anyone see a slowdown in activity for standalone storage where there is no tax credit currently, but there may be one in the future? [Silence] I will take that as a no.

Let me ask another question related to the Wyden bill that cleared the Senate Finance Committee the last week in May. Catherine Wolfram, the deputy assistant Treasury secretary for climate and energy economics, said in a short talk immediately before this panel that a quid pro quo for claiming new, larger tax credits will be compliance with labor requirements.

The Wyden bill requires all construction contractors and subcontractors working on a project to pay federal Davis-Bacon wages not only during construction, but also when making repairs or improvements during the full period tax credits are claimed or are subject to recapture. Developers are worried that tax credits could be clawed back later if a contractor over whom they have little control promises but fails in fact to do this, and they are worried that the tax equity market will make them take the risk. Does any of you see anyone starting to address this in documents or is it too early?

MR. NOURAFSHAN: In terms of documents, it is too early. It is something that we are monitoring and thinking about as we formulate our plan with respect to construction contracts on future projects.

MR. MARTIN: Vishal Kapadia, does this come up in any conversations with financiers?

MR. KAPADIA: Not yet. Like Andrew, we are monitoring it.

MR. MARTIN: Going back to Meghan Schultz, how is tax-change risk being handled currently in deals?

MS. SCHULTZ: I would put it in two buckets. You have the risk of a change in tax law during the period after the documents are signed through the actual funding and then for the life of the investment.

I think that sponsors and tax equity investors are used to addressing change-in-tax-law risk as it relates to tax rate change. That is easy. You can quantify and address it. The harder questions are what happens if a project suddenly becomes eligible for a refundable tax credit or something like that.

There could be a situation where you would rather not raise tax equity if Congress offers a direct-pay alternative to tax credits. The response to that may be to try to buy a little time, if the project schedule supports it, before we actually execute the tax equity transaction. I don't think investors are looking to provide much flexibility once the deal papers are signed.

MR. MARTIN: Steve Ryder, are you finding any tax equity investors willing to give you the flexibility to pull out later if Congress enacts a direct-pay alternative to tax credits?

MR. RYDER: We have had to navigate similar issues in the past with regard to state refundable tax credits, and we have found that tax equity investors have been willing to work with us. That makes me think that if we have to deal with similar issues at the federal level, sophisticated tax equity investors will have a similar mindset.

MR. MARTIN: What is a possible compromise between letting you walk and holding you to the deal?

MR. RYDER: I would rather not get into the details about what we have done at the state level versus what might happen at the federal level.

MR. MARTIN: James Marshall, Meghan Schultz said there are two buckets of tax-change risk. One is a tax change that occurs before funding and the other is what happens after. Are you seeing tax equity investors get protection for tax law changes after funding and, if so, for how long?

MR. MARSHALL: We are seeing a framework similar to what evolved the last time we were in a tax reform environment, but we are still working through this.

MR. MARTIN: The last time was 2017. Tax equity investors made it a condition precedent to each funding that the pricing model had to reflect proposed changes in tax law. There was an adjustment later if the change was not ultimately enacted by the end of 2018. However, some tax equity investors looked for longer-term protection against future tax-law changes almost as if they were lenders. Are you seeing that this year?

MR. MARSHALL: We have yet to encounter that.

MR. MARTIN: Vishal Kapadia, how do you see tax-change risk being addressed?

MR. KAPADIA: We are in a bit of a different world than we were the last time a potential change was on the horizon in that this time the risk is to the upside. There are obviously a number of details to be worked through in terms of how to be able to capture that upside if you are a sponsor and on what timetable. Our discussions about this issue have not been terribly contentious since it is probably an upside case for most projects.

Other Market Shifts

MR. MARTIN: Meghan Schultz, going back to you, has anything changed about the tax equity market this year compared to 2019 or 2020, aside from the difficulty finding investors for ITC deals?

MS. SCHULTZ: Addressing change in tax laws is probably the primary topic, but I don't see any fundamental changes to the tax equity market itself.

MR. MARTIN: James Marshall, same answer?

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Biden has ambitious plans that include social infrastructure that would have to be packaged with more traditional infrastructure to put through under a single budget reconciliation card.

If a bipartisan bill emerges, it would also complicate action on clean energy if clean energy is not included because it is unclear the Senate has the time or appetite to pass two infrastructure bills this year.

Meanwhile, the Senate Finance Committee voted the last week in May for a Wyden tax credit bill that would rewrite and increase tax credits on clean power plants, energy storage facilities and new transmission lines at 275 KV or higher voltage that are placed in service after 2022. The new tax credits would be allowed on projects that are completed in 2022 or later even though they are already under construction when the bill is enacted. Tax basis would count for the investment tax credit only to the extent built up after 2022. The committee staff may still be thinking about the transition rules.

Project owners would have the option to receive the new tax credit value in cash through an IRS refund process with a one-year lag.

However, there is a tradeoff. To qualify for the new tax credits, contractors and subcontractors would have to pay prevailing wages as determined by the US Department of Labor, and use qualified apprentices for at least 15% of total labor hours, not only during construction but also on repairs and improvements during the 10-year period that production tax credits are claimed or the five-year recapture period if an investment tax credit is claimed.

Senator John Cornyn (R-Texas) tried to strike language in early June in a proposed US Competition and Innovation Act that would require payment of prevailing wages by semiconductor manufacturers in exchange for federal assistance to ramp up semiconductor production at "mature nodes." The / continued page 7

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MR. MARSHALL: Agreed. I am aligning with Meghan on this one.

MR. MARTIN: Does anyone have a different answer?

MR. RYDER: I think there is a lot more focus on sponsors this year. Events like the Texas storm and other black swan events make tax equity investors look more carefully at the ability of sponsors to navigate through and withstand such events.

MR. MARTIN: So there is a move perhaps to sponsors who are better capitalized and, if we had a panel of smaller sponsors, we might hear that raising tax equity is even more difficult than last year.

Is anyone seeing any new tax equity investors this year?

MR. KAPADIA: We have not seen new entrants to any material degree. However, our focus of late has been on utility-scale projects on the larger end of the spectrum, which tends to drive us to the usual-suspect group of investors with the ability to deploy capital at scale.

MR. MARTIN: Is anyone else seeing any new tax equity investors? We have seen 17 tax equity investors since last September who either have come back into the market or are new entrants. Many are investing alongside more experienced investors rather than on their own.

MR. NOURAFSHAN: New tax equity investors do not show up overnight. There is a long lead time of education and familiarization with the idiosyncrasies of this type of investment. There is a lag between when an investor starts looking at tax equity and when it ultimately gets comfortable signing documents and making commitments.

Last year was a disruptive year. We have had some new investors on our deals, but we are spending a lot more time focusing on cultivating new investor relationships in the hope that they bear fruit in future years, as opposed to a deal that we would execute this year.

MR. MARTIN: James Marshall, tax equity last year seemed to account for about 35% of the capital stack, plus or minus 5%, for the typical solar project and 65%, plus or minus 10%, for the typical wind project. You do solely solar. Does 35% sound like the right percentage this year?

MR. MARSHALL: It does. It depends on how large an ITC the project can claim, but I don't think anything has changed.

MR. MARTIN: Meghan Schultz, you do both wind and solar. Do these figures sound right?

MS. SCHULTZ: Yes. They are in line with what we are seeing.

Current Yields

MR. MARTIN: Steve Ryder, where are you seeing current yields, and are they moving up or down?

MR. RYDER: We closed a deal earlier this year where the flip yield was sub-6%. The deal did not have a lot of risk to it. It had a long-term PPA and did not have issues like basis risk or shape risk that may be of concern to tax equity investors in other transactions. People were also comfortable with our ability as a sponsor to execute and construct the project on time.

I don't think having a flip yield in the 6% range is necessarily an outlier if you have a well-constructed project. That is where we are getting indicatives for a number of our financings coming down the line.

MR. MARTIN: In the 6% range meaning mid-6%, high 6%?

MR. RYDER: Mid-6%.

MR. MARTIN: I am guessing the deal you closed at a sub-6% flip yield was a wind project.

MR. RYDER: That's correct.

MR. MARTIN: Meghan Schultz, where are you seeing current yields?

MS. SCHULTZ: I don't think I have anything to add beyond

It is harder to find tax equity for ITC projects than for PTC projects.

seeing yields in the range that Steve mentioned.

MR. MARTIN: James Marshall, what about you?

MR. MARSHALL: I agree. We generally see in the 6% to 7% range, and it flexes depending on the commercial structure and the length of the power contract.

MR. MARTIN: We have been seeing 7.25% to 7.5% lately for contracted utility-scale solar projects. The fact that many of you are seeing yields in the 6% range may be a sign that you work for very experienced sponsors with longstanding bank relationships. Vishal Kapadia, where are you seeing current yields?

MR. KAPADIA: Obviously a number of factors drive the flip yield, including project location, offtake structure, overall risk profile and sponsor quality. Generally I would say they are in the 6% to 7% range, but with upward drift on the back of the events in Texas and the macro environment of rising interest rates.

MR. MARTIN: Andrew Nourafshan?

MR. NOURAFSHAN: This is always the question you ask your investor panels and they are coy, too. I don't know that I have anything else really to offer other than to underscore that project quality and offtake characteristics are the name of the game here, so flip yields vary. To the extent we have seen any upward drift on Texas projects since February, it has not been dramatic. There has been a heightened focus on diligence, scrutiny of projects and underwriting the black swan event or downside cases more than any meaningful change in pricing.

Direct-Pay Alternative

MR. MARTIN: Meghan Schultz, will you still do tax equity if Congress enacts a direct-pay alternative?

MS. SCHULTZ: It depends on the project. We have solar projects ranging from 70 to over 1,000 megawatts, and we are in solar, onshore wind and offshore wind. It depends on the profile of the project, the timing and our ability to monetize the depreciation. We would continue to raise tax equity for some projects, but not for all.

MR. MARTIN: The direct-pay proposals in Congress would operate through the IRS and treat the tax credit as a tax overpayment that can be recovered through a refund process after the tax return is filed for the year the project is placed in service. Thus, you would not be able to file for a refund for a project that goes into service in 2023 until something like September 2024. In 2009 through 2016, people continued to raise tax equity even through the Treasury was making cash payments in lieu of tax credits under the section 1603 program. The application for a cash payment could be filed immediately */ continued page 8*

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effort failed 42 to 58 as eight Republican Senators joined with Democrats to support the wage provision.

The Senate Finance Committee vote on the Wyden bill was an effort by the committee chairman, Ron Wyden (D-Oregon), to put down a marker for a technology-neutral approach to tax credits in any infrastructure bill that moves this year. Any infrastructure bill is expected to move through the House first before trying to clear the Senate. (For more details about the Wyden bill, see "Wyden bill and tax credits" at www.projectfinance.law.)

PRESSURE IS MOUNTING to take action on solar panels that use materials or components made in the Xinjiang region in western China.

A fact sheet issued by the White House at the conclusion of the G7 meetings in Cornwall on June 13 said, "The United States and our G7 partners remain deeply concerned by the use of all forms of forced labor in global supply chains, including state-sponsored forced labor of vulnerable groups and minorities and supply chains of the agricultural, solar, and garment sectors — the main supply chains of concern in Xinjiang."

Richard Neal (D-Massachusetts), chairman of the House Ways and Means Committee, and 23 other committee Democrats sent a letter to acting US Customs head Troy Miller on June 10 asking why Customs has not moved to block solar panels made with polysilicon from Xinjiang from entering the US. The letter said committee members were promised action was imminent nearly three months ago.

The Senate Finance Committee added language to the Wyden tax credit bill in late May to bar solar cells, wind turbines and batteries from being imported into the United States until the United Nations certifies that such equipment does not use materials or components mined or manufactured using forced or child labor. The language was proposed by three Republicans on the committee led by

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after a project went into service.

You said it depends on some factors. When would you choose not to raise tax equity?

MS. SCHULTZ: We will need to see the details of the new law, but it sounds like there may be an ability to bridge the cash payment through lower-cost debt rather than tax equity.

There may also be situations where we are able to use the depreciation ourselves. This will require an evaluation of the capital structure for each project.

MR. MARTIN: That's interesting. The fact that debt can be used to bridge more cheaply than tax equity may put downward pressure on tax equity yields.

MS. SCHULTZ: You would think, although tax equity yields have proven to be pretty inelastic over the years.

MR. MARTIN: Your CEO, Michael Polsky, has been complaining about them since at least 2004. James Marshall, will you still do tax equity if there is a direct-pay alternative?

MR. MARSHALL: We have done a lot of analysis about this. The final decision will depend on the details of the direct-pay option. However, it is hard to imagine us not doing at least a mix of tax equity and electing direct pay. Moving wholly to direct pay without any tax equity seems less likely for us.

MR. MARTIN: Steve Ryder, Meghan Schultz made a good point, which is if you are going to use bridge financing, debt is cheaper, but of course, that still leaves depreciation. The tax credits are worth about 30¢ and depreciation is worth about 14¢ per dollar of capital cost of a project. That is a lot of value to leave untapped. Is there room still for tax equity in a direct-pay world?

MR. RYDER: Yes, there is. We will probably use a combination of direct payments and tax equity, depending on specific project fundamentals.

The other thing is it will take some time for the market to adjust to direct payments. The tax lawyers will look at the final legislation. There will be a bunch of questions that the market will want the IRS to answer. It takes time for the IRS to issue guidance. In the meantime, the tax equity market will continue to function as it does now.

MR. MARTIN: Vishal Kapadia, how important is it that Congress enact a direct-pay alternative?

MR. KAPADIA: It is important from the standpoint of adding liquidity to the market and addressing some of the issues that we have just been talking about in terms of difficulty unlocking ITC capital for solar projects and the challenges that developers below the top tier still face raising tax equity.

MR. MARTIN: Andrew Nourafshan, will Cypress Creek still do tax equity if it has the option of taking cash?

MR. NOURAFSHAN: You will hear the same refrain from me. We do not have enough detail, nor do I think even if we had all the detail we would, with conviction, suggest one versus the other. It will end up a mix. We welcome having a broader set of liquidity options, but the details matter of how this will be implemented.

Chinese Equipment

MR. MARTIN: Meghan Schultz, Biden issued an executive order setting aside the Trump executive order that made it illegal to buy or use Chinese and other foreign adversary equipment that might harm the US power grid. It was never clear to the market what exactly that equipment is. Did Invenergy change any of its equipment procurement as a consequence of the Trump order?

MS. SCHULTZ: We did not. Like everyone else, we certainly spent time last year trying to understand what the order meant, but we decided ultimately that it did not require any changes in our equipment purchases.

MR. MARTIN: Steve Ryder, are tax equity investors or lenders showing any concern about purchases of Chinese transformers, panels, inverters or batteries or that such items, if purchased, might have to be replaced?

MR. RYDER: No, we have not heard that kind of concern from tax equity investors. When it comes to things like batteries, our view is we do not see a risk to the bulk-power system.

MR. MARTIN: Both tax equity investors and lenders push the replacement risk off on the sponsor, correct?

MR. RYDER: Depending on the transaction, yes. We do not believe the risk is significant.

MR. MARTIN: James Marshall, same answer?

MR. MARSHALL: Yes. We were asked questions when the Trump executive order first came out, but the issue seems to have died down. I agree with respect to risk allocation.

MR. MARTIN: Vishal Kapadia, the other big issue related to China of course is the Xinjiang region of western China and Uighur forced labor. Congress has been threatening to block entry of any equipment that uses material or components made in Xinjiang. Have you seen this play a role in any financing, and has it affected your equipment procurement? The solar industry issued a tracing protocol in late April.

MR. KAPADIA: We do everything we can to ensure that no forced labor is used for solar modules within our supply chain. We signed the solar industry forced labor prevention pledge. We are following the tracing protocol, but global supply chains are not always fully transparent.

There is an incremental focus on equipment manufacturers that are relatively insulated from the issue. It may be that, depending upon how things evolve and how the tax equity market ultimately responds to the issue in terms of risk allocation, that we need to think about deferring some investments or accepting lower economics while we work through the concerns around forced labor and perhaps focus on equipment vendors who are less exposed to the issue.

It is a discussion that has come up in passing with tax equity investors. As you would expect, their initial position is to try to push the risk off on sponsors, but there is an education process going on across the market.

MR. MARTIN: Has anyone changed solar panel suppliers for fear of Uighur issues? At least three solar panel manufacturers have acknowledged publicly that they source polysilicon from the region. Various publications have also identified four polysilicon suppliers as benefitting potentially from Uighur labor.

[Silence] I will take that as a no. It is easy in financing discussions to push these risks off on the sponsors.

Inflation

MR. MARTIN: Steve Ryder, there has been an uptick in the last two months in inflation. Are inflation concerns starting to affect the market, and if so how?

MR. RYDER: I think everyone is thinking about inflation these days. One challenge is that a number of PPAs signed recently have flat electricity prices as opposed to having CPI adjusters. If you have such a contract, then you need to think more carefully about how the cost side of your project might be affected by inflation over the PPA contract term. This has become top of mind lately.

MR. MARTIN: Meghan Schultz, how are you thinking about inflation?

MS. SCHULTZ: We are seeing the impact of inflation through commodity price increases in the near term. They are affecting projects that we will have under construction over the next 12 months. These are projects where we may have already entered into a fixed-price build-transfer agreement or PPA. In many cases, inflation risk is on the sponsor. There is also interest-rate risk. The challenges are around all of those. */ continued page 10*

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Richard Cassidy (R-Louisiana). The committee hopes to fold the Wyden bill into a large infrastructure bill later this summer.

Tax equity investors and lenders are evaluating what happens if Chinese solar panels are blocked from entry in cases where the financing has to fund before the panels are in the United States.

The Solar Energy Industries Association issued a supply chain traceability protocol in late April with detailed recommended procedures to ensure that use of materials or components originating in Xinjiang can be traced through the supply chain. Companies importing solar panels into the US are expected to be able to provide supply-chain maps showing every step in the manufacturing process from the raw materials to the finished goods.

Tracing will require, among other things, balancing output with inputs at each step in the manufacturing process. For example, if a factory ships 3,000 solar panels a day with 72 full-size cells per panel, then the factory should be bringing in approximately 6.5 million cells per month.

A staggering amount of documentation is expected to be retained to prove the provenance of materials. "Documented information shall be retained that identifies specific quantities and volumes of materials, e.g., modules, cells, wafers, etc., that are transformed at each step in the supply chain and transferred between steps." Presumably manufacturers already keep this information in their computers.

Manufacturers are expected to impose these requirements down the supply chain. Solar companies are expected to choose module suppliers based on their willingness to implement these procedures.

If a US solar company finds that a supplier is not complying, then it is expected to reject or quarantine the panels. This requires writing such a right into the module contract.

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MR. MARTIN: James Marshall, how is inflation playing into what you do?

MR. MARSHALL: We are also seeing some wage inflation. The labor market is tight, in particular for the workforce we are trying to hire to build our solar facilities. We see less such pressure in the wind market. We are trying to sign up the EPC contracts earlier as a way of locking in prices.

MR. MARTIN: Vishal Kapadia, are you interested in project bonds, which of course are fixed-rate debt, as opposed to the floating-rate debt that tends to be used to finance projects?

Supply-chain dislocations are pushing up construction costs for projects that have little room to spare on the revenue side.

MR. KAPADIA: We have the benefit of a large balance sheet with efficient funding costs and, therefore, tend not to make use of project finance debt here in the US.

MR. MARTIN: Meghan Schultz, is there any talk at Invenergy of moving to project bonds?

MS. SCHULTZ: I am not sure they are the answer to some of the issues we are seeing. Project bonds are only suited to certain types of long-term financing. The project has to be of a certain size and have the right type of offtake agreement. We always look at them as an option, but I don't think how we look at them has changed in the current environment.

MR. KAPADIA: Overall, I think the message from all of us is that costs are meaningfully escalating across the board, whether it is underlying commodities costs, pressure on the transportation side, the balance-of-plant side, insurance, even talent. Then you layer that against a backdrop where interest rates are drifting up. The implication of all this is that the utility and corporate offtakers, who have benefitted over the past five to seven years from continued declines in energy pricing, need to start to condition themselves to paying a bit more for their electricity.

MR. MARTIN: Of course that is fine for future contracts, but if your costs are going up for existing contracts that you can't change, you are kind of stuck, right?

MR. KAPADIA: That is certainly the case in some instances. To an extent, what happens depends on the offtake counterparty and the strength of the relationship. Many offtakers are willing to be constructive, certainly in cases where it comes down to there will not be any project unless the changes are made.

MR. MARTIN: We are down to the last two minutes. Andrew Nourafshan, have you seen any changes in the willingness of lenders to do back-levered debt or in the interest rates, tenors, debt-service-coverage ratios or other terms for debt?

MR. NOURAFSHAN: Not really. The only change has been a reversion to where we were pre-COVID in some respects. There was a bit of a spike in pricing and coverage ratios early last summer. The concerns that led to that have largely been assuaged. General lender appetite remains strong, and there is a lot of appetite for projects among back-levered lenders. We are seeing pricing and sizing trending in the direction that developers want.

MR. MARTIN: Meghan Schultz, where are current spreads for back-levered debt today: 125, 137.5, 175 basis points over LIBOR?

MS. SCHULTZ: I think it depends on the profile of the project and the offtake contract. You can get something at the tighter end of that spectrum for a well-structured project. ◎

Diagnosing Weather-Driven Financial Risk in Hedges

by Gregory S. Poulos, with ArcVera Renewables in Golden, Colorado

Hedged financial structures with guaranteed production for wind farms are misdiagnosed with respect to weather risk, with asymmetric price risk, meteorologically unrealistic production assurances and strike prices that do not reflect long-term electricity prices.

As renewables increase as a percentage of US generating capacity, the consequences of misdiagnosis of financial risk in hedges increases proportionally.

The five-day Texas cold snap in February caused wind farms in ERCOT to sustain financial impacts of more than $4 billion — greater than twice their annual gross revenues.

The worst direct losses were suffered by project companies with fixed-volume hedges and proxy revenue swaps. Iced wind farm projects with as-generated financial structures lost the opportunity to profit from the $9,000-per-megawatt-hour price during the event.

How can financial modeling and stress tests assess the extreme weather event risk of hedges?

Key Numbers

All wind farm hedges in ERCOT share one important characteristic that has been ineffectively diagnosed by current practice: they have a highly asymmetric risk that can cause enormous losses in very short periods of time.

Hedges placed in other markets are subject to similar asymmetry, although with different maximum electricity prices.

Hedge risk assessment must account for extreme pricing in extreme weather if project wind turbines are not weatherized to operate through extreme weather.

The estimated average financial impact of the Texas February cold snap on an individual Texas wind farm without icing mitigation capability and based on common net capacity factors of Texas wind farms was $45 million. This exceeds the typical nominal annual revenue by more than two times.

This financial impact is many times a wind farm's annual net income and, therefore, depending on the financial structure, negates a large fraction of a project's / continued page 12

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clean up supply chains could soon broaden to child labor in cobalt mines in the Congo. Cobalt is an essential ingredient in rechargeable lithium-ion batteries.

The Clean Power Alliance, the community choice aggregator for Los Angeles and Ventura counties in California, is requiring solar developers signing long-term power contracts to sell it electricity to ensure that their "direct" equipment suppliers comply with a broad supply-chain code of conduct. Failure to do so could lead to a default and, if not timely corrected, loss of the power contract.

The code addresses a variety of labor issues. Electricity generators would be expected to impose these requirements on their solar panel, inverter and other equipment suppliers. The Clean Power Alliance reserves the right to audit to confirm compliance.

Workers must be free to quit. They cannot be under age 15 or, if higher, the minimum age to work in the country. The work week cannot be more than 60 hours, and they need at least one day off every seven days.

Workers must be paid at least the minimum wage and other benefits required under local law and be paid overtime pay at higher rates than the regular hourly wage.

There cannot be discrimination or harassment tied to any of the following: "race, color, age, gender, sexual orientation, gender identity and expression, ethnicity or national origin, disability, pregnancy, religion, political affiliation, union membership, covered veteran status, protected genetic information or marital status in hiring and employment practices such as wages, promotions, rewards, and access to training."

Workers have to be provided with reasonable accommodation for religious practices and must be free to join unions.

Kat Gamache, with Norton Rose Fulbright in Washington and Houston, said the Clean Power Alliance tends to lead the CCA pack in terms of power / continued page 13

Hedges

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lifetime return and creates a significant risk of default.

The project company risk is 225 times higher than that of the hedge provider for any given hour in ERCOT. If an electricity price floor is used, then the difference would be larger than 225 times.

Weather risk is being misdiagnosed in some hedged financial structures.

The asymmetry arises from the difference between the hedge strike price, perhaps $16 per MWh, and the lowest price that a project can tolerate without losing money (-$25 per MWh, negative production tax credit during negative pricing events) and highest price in the market ($9,000 per MWh in ERCOT). The project company takes risk up to the difference between the highest price and the strike price, $8,984, and the hedge provider takes risk up to the difference between the lowest negative price and the strike price, $16 – (-$25), or $41. In some cases, the hedge provider will place a floor of $0 per MWh on the electricity price, which limits its risk in this case to $16 and further exacerbates the risk asymmetry.

The assumption that the maximum project company risk value will seldom be achieved is inherent when a project company enters into a hedge, presumably resulting in a strike price with balanced risk for both parties. It is not in the interest of either party to enter into a hedge transaction that results in default.

The meteorological record suggests that cold-weather and icing outage events will occur several times during the 30-year useful life of a wind farm in much of Texas. Such events can occur in any year during the cold weather season.

A cold snap the magnitude of the February 2021 event is rare, but can be expected approximately every 10 years. The last major event occurred in February 2011, almost exactly 10 years before the most recent event.

These cold weather realities, along with similar risks associated with peak demand in hot weather, need to be properly reflected in the risk assessment of the hedged financial products, particularly where a renewable energy plant owner has an obligation to deliver potential production (proxy generation) or long-term mean hourly electricity production (fixed shape) to a financial counterparty. The February ERCOT crisis revealed that most wind farm owners had not properly appreciated the asymmetry in value between the benefits of the fixed revenue stream and the enormous potential liabilities from weather, plant unavailability, and regulatory events.

The most accurate way to assess the financial risks associated with extreme weather, and other relatively less common but severe weather-driven impacts, such as a months-long period of below average production, is with long-term, high-fidelity, project-specific, hourly, time series modeling of renewable energy power plant production with concurrent weather-dependent pricing.

Such time series are 10 to 40 years in length and enable a realistic distribution of low-side and high-side financial scenarios to be clearly understood, both statistically and in absolute quantitative terms. Fixed-shape and fixed-volume arrangements can be tested against this production time series to reveal worst case but realistic circumstances of unmet or excess production and their financial impacts. These time series reveal specific event scenarios that create stress on a given financial scenario, and prior to execution of the hedge, allow its financial structure to reflect a much more complete spectrum of possible outcomes. These same time series can be used to evaluate the financial benefit of weatherization strategies for hot, cold or icing conditions, within the context of a given as-generated or fixed-shape model.

Strike Prices

Strike prices should reflect something closer to the true price of power.

It is clear that the price of electricity in Texas is much higher than the 2020 average of $20 a MWh. In ERCOT, the total amount of electricity purchased during the February 2021 cold snap was $46 billion, or six times the total value of all electricity purchases in 2020. In 2020, ERCOT electricity purchases summed to $7.6 billion at an average purchase price of $20 a MWh.

Even if the February 2021 cold-snap pricing anomaly is spread over the 10 years between such events, the average price of power in ERCOT is increased by $12 a MWh over the 2020 value to $32 a MWh.

If structural changes are not made to the ERCOT grid and market operation, and weatherization is not implemented on renewable energy projects, future Texas contracts should reflect a price of between $30 and $40 a MWh, that accounts for unavailability during extreme weather events and very high ERCOT pricing for a few days per year.

In this case, the increase in revenue would need to be set aside in an escrow structure or tracking account where peak-event high financial impacts can be rectified as they occur. The immense size of this account probably removes this option from consideration as a palatable financial structure.

As-generated production hedges remove the asymmetric risk associated with unavailable turbines, although the lost opportunity to sell electricity in extreme weather conditions remains, and asymmetric high-side project owner opportunity cost is unabated. In this case, the owner loses the opportunity to sell power during those extreme weather and demand moments when electricity prices spike to 50 or even 450 times their average.

Business interruption insurance, energy call options and per-megawatt daily caps to limit risk asymmetry, and avoiding fixed-volume hedges and using only as-generated hedges are all possible solutions.

Appropriate force majeure clauses in hedge agreements could also mitigate the asymmetric price risk that is present mainly during extreme weather events, but they would not increase the physical availability of generation as renewables continue to penetrate energy markets.

Another way to address asymmetry is to require that the hedge provider also provide loss caps, so that both sides of the deal are exposed to the same, or at least similar, ranges.

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contract provisions, so she expects other CCAs to take a similar approach.

CCAs are city or county local procurement aggregators that buy electricity for their resident members, often from renewable energy suppliers. There are 24 such CCAs currently in California. They supply a quarter of the electricity load. Most new renewable energy power contracts in the state are with CCAs.

HYDROGEN TAX CREDITS are starting to take shape in Congress.

The tax credits would reward production of "clean hydrogen," meaning hydrogen made with a process that emits at least 50% less carbon dioxide than use of steam-methane reforming to separate hydrogen from natural gas.

The lower the emissions compared to steam-methane reforming, the larger the tax credit. Emissions reductions would have to be determined by looking at emissions over the full lifecycle to produce the hydrogen.

The Senate Finance Committee approved the tax credits the last week in May as part of its markup of a Wyden energy tax credit bill. (For more information about the bill, see "Wyden bill and tax credits" at www.projectfinance.law.)

The markup was an effort by the committee chairman, Ron Wyden (D-Oregon), to lay down a marker as Congress considers possible action to promote clean energy this year as part of a massive infrastructure bill. Any infrastructure bill is expected to start in the House.

The bill that cleared the Senate Finance Committee would give hydrogen producers a choice of two tax credits: production tax credits as high as $3 per kilogram of hydrogen produced in the first 10 years after the electrolyzer or other production equipment is first put in service or an investment tax credit for as much as 30% of the equipment cost. The investment tax credit would be claimed entirely in the year the equip-

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Using the earlier figures, the hedge provider is exposed from the negative $25 electricity price plus $16 strike price, or a net of $41, so the project owner losses could be capped near $16 plus $41, or $57, for example.

Since negative pricing events are more frequent than extreme high pricing events during extreme weather and demand, the owner cap would probably be higher than this amount to balance risk more closely. In practice, a loss cap that represents balanced price risk for a given project can be calculated using the long-term time series analysis described earlier. More practically, a loss cap that reasonably prevents default is in the interest of the parties. In effect, loss caps would only be reached during extreme pricing anomalies, which are usually associated with extreme weather and demand, so the loss cap is a financial means of protection against extreme weather-induced price risk. This is a financial of form force majeure protection.

The project company risk is 225 times higher than that of the hedge provider in any given hour in ERCOT.

Reconsidering Weatherization

Similar, if most likely shorter, icing and cold weather events will occur several times during the 30-year useful life of a wind farm in much of Texas. These conditions are less likely for projects along the Texas Gulf coast. Gulf coast projects are more likely to be affected by a different extreme weather event: hurricanes.

After the 2011 cold weather event, which also caused rolling blackouts in Texas, the Federal Energy Regulatory Commission and North American Electric Reliability Corporation reported that similar events had occurred in 1983, 1989, 2003, 2006, 2008 and 2010.

Texas currently has 25,121 megawatts of wind capacity, mostly unprotected from icing events. Icing mitigation adds approximately 5% to 10% to turbine prices or $50,000 to $100,000 per megawatt at $1,000,000 per megawatt at purchase. Thus, upfront icing mitigation of all wind turbines in Texas would have cost $1.25 to $2.5 billion. With hindsight, the cost of icing mitigation would have been less than the $4.2 billion impact of the latest icing event.

Developers of wind farms in the ERCOT market and elsewhere often eschew weatherization packages, rendering wind farms inoperable in extreme heat, extreme cold and when iced. The basis for these decisions can be that 1% of production is removed by unmitigated icing per year. In this example, at an average $20 a MWh electricity price, this 1% of production per megawatt costs no more than $1,800 per installed megawatt at risk per year — insufficient to justify the price of de-icing equipment.

This calculation is errant. Electricity prices during cold weather events are $500 to $9,000 a MWh, with a more common ERCOT value near $1,000 a MWh. At $1,000 a MWh, the annual lost production due to 1% icing is up to $88,000 per year and de-icing equipment is more fiscally rational.

Weatherization packages are available from wind turbine manufacturers and from third-party after-market suppliers. These can take the form of cold-weather packages, including heaters and special lubricants to allow operation at colder temperatures.

As the penetration of renewables increases over time, it could lead to more competition among equipment suppliers and could cause de-icing package prices to drop well below the less attractive current rate of 5% to 10% of turbine price. ◎

Reawakening the DOE Loan Guarantee Program

by Kenneth Hansen, in Washington

Both the Department of Energy and the White House have been broadcasting that DOE has more than $40 billion in loan guarantee capacity available to support clean energy projects.

Given that this capacity has gone largely unused for roughly the last decade, one might reasonably wonder how real is the availability of those resources. It seems to be quite real — and recent program changes should make it more so.

The $40 billion capacity resides in different buckets.

Within the title XVII innovative energy project financing program, $4.5 billion is currently allocated to be made available pursuant to a solicitation the department issued in 2014 for renewable energy and energy efficiency projects. Another $8.5 billion remains under a 2013 solicitation for fossil energy projects. Another $10.9 billion remains under a 2014 solicitation seeking applications for advanced nuclear projects.

Seventeen billion in direct loans remain available under an advanced technology vehicle manufacturing program.

Finally, $2 billion was authorized in 2020 to be deployed as partial (90%) guarantees of commercial loans pursuant to a tribal energy loan guarantee program.

The capacities of these various programs total $42.3 billion.

Renewables are currently the poor cousin in the triad of open solicitations for innovative projects under the title XVII program. Only $4.5 billion of the total $24 billion remaining under those solicitations is available for them. That allocation is not statutory, but rather the outcome of discussions with the relevant Congressional oversight committees. If demand in the project pipeline were to suggest that some reallocation would make better use of the resources supporting these solicitations, then that could be done without legislative action, assuming there is the political will.

Terms on Offer

Under the title XVII program, the government guarantees repayment of 100% of the principal and interest on loans for up to 80% of the costs of constructing energy projects in the United States that embody innovative technologies / continued page 16

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ment is first put in service. The production tax credit amount would be adjusted annually for inflation.

The carbon emissions would have to be at least 95% lower than for hydrogen produced from natural gas using a steam-methane reforming process to claim the full tax credit. A clean hydrogen producer who does not reach at least 95% would qualify for tax credits at only 20% to 34% of the full rate.

Hydrogen producers would have the option to be paid the cash value of the credits under an IRS refund process with a one-year time lag.

The tax credits are retroactive. They would cover hydrogen produced or electrolyzers put in service since the start of this year.

However, they could not be claimed unless contractors and subcontractors working on the project pay at least prevailing wages as determined by the US Department of Labor and use qualified apprentices for at least 15% of total labor hours, both during construction and when making any repairs or improvements during the full period tax credits are claimed or, where an investment tax credit is claimed, during the five-year period the ITC is subject to recapture.

Meanwhile, the US Treasury released details of a low-carbon hydrogen tax credit that the Biden administration favors. The details are in a "green book" that the Treasury released at the end of May.

The Biden tax credit would be simpler to administer, but could be less generous.

Production tax credits could be claimed for making hydrogen from renewable or nuclear electricity and water during the first six years after the electrolyzer is first put in service. The credit would be $3 a kilogram "between 2022 and 2024" and $2 a kilogram "between 2025 and 2027." The credit amounts would be adjusted for inflation.

Credits could also / continued page 17

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and reduce greenhouse gas emissions.

Guaranteed loans can have terms up to the shorter of 30 years and the useful life of the financed assets.

Notwithstanding the statutory maximum of 80% leverage, the department must also achieve a "reasonable prospect of repayment." Thus, DOE is unlikely to offer a debt-to-equity ratio higher than what might be expected in commercial project financings. Depending on coverage ratios and the security of projected offtake, leverage in the neighborhood of 65% to 75% is more likely. As to term, again commercial benchmarks, such as a year or so less than the term of an offtake agreement, are likely to guide DOE's offer.

The application process consists of filing a part I application with enough information for DOE to determine whether the project qualifies and is ready to proceed to a part II application. The part II application provides a deeper dive into the technical and financial details of the project. If that passes muster, then DOE will move to full diligence, including hiring external counsel and other consultants to assist in that review. That leads to issuance of a conditional commitment and, if all goes well, definitive documentation and financial close.

The innovative energy projects program has been open for more than a decade. All of its 29 financings to date (except for the Vogtle nuclear power project) were closed from 2009 to 2011. Two important changes have been made since then to make the program a more accessible and reliable financing partner.

Recent Changes

Congress amended the loan guarantee statute last December in the Energy Act of 2020 to make a number of adjustments in how the program works.

Applicants no longer have to pay application fees and reimburse DOE for the fees charged by its external advisors until financial close.

The part I application fee is $50,000. The part II application fee is $100,000 (or $350,000 if a guarantee of more than $150 million is sought). There is a facility fee of 1% of the first $150 million guaranteed plus 0.6% of any additional amount. Successful applicants must also reimburse DOE for the fees of its outside advisors such as legal counsel and independent engineers.

The applicant's risk of being required to pay these fees without seeing the benefits of a closed financing has now shifted from the applicant to DOE. No fees are payable until closing. If there is no financial close, then DOE foregoes the application fees and picks up the advisory fees itself.

More types of projects now qualify.

Projects that "avoid, reduce or sequester air pollutants or anthropomorphic emissions of greenhouse gases" qualified in the past, but now ones that use such pollutants or emissions also qualify. Energy storage projects that use "technologies for residential, industrial, transportation and power generation applications" now qualify. So do carbon capture projects involving "synthetic technologies to remove carbon from the air and oceans" and projects involving "technologies or processes for reducing greenhouse gas emissions from industrial applications, including iron, steel, cement, and ammonia production, hydrogen production, and the generation of high-temperature heat."

Facilities for the "manufacturing of nuclear supply components for advanced nuclear reactors" will now qualify.

Congress loosened the standard for what makes a project "innovative." In the past, a technology was not considered innovative if more than two projects have been using that technology in the United States for at least five years. Going forward, the program is authorized, "if

Roughly $40 billion in DOE loan guarantee capacity to support clean energy projects has sat largely unused for a decade.

regional variation significantly affects the deployment of a technology," to issue guarantees "for up to 6 projects that employ the same or similar technology as another project, provided no more than 2 projects that use the same or a similar technology are located in the same region of the United States."

The department has had trouble issuing loan guarantees in the past on a reasonable commercial timetable. Applicants can now get a status update within 10 days if an application has been pending for at least 180 days — and every 60 days thereafter — including an estimate of when a final decision will be made.

Program Quirks

The Department of Energy revised the implementing regulations for the loan guarantee program in 2016 to address assorted quirks in the original regulations that were adopted in 2007, when the program was disfavored by the administration charged with implementing it.

A quick round of amendments was implemented in 2009 to address the most egregious issues when, in the midst of the financial crisis, the program was provided the opportunity and responsibility to deploy substantial capital in innovative energy infrastructure.

In 2015 and 2016, a quiet project pipeline gave DOE the opportunity to undertake an update to make the regulations more consistent with the needs of the program and commercial norms. Most of the 2016 amendments were of technical details unlikely to interest program participants. A few changes had substantial positive consequences.

The regulations have now been updated again. A key development is the following new provision:

[A] potential Applicant may request a meeting with DOE to discuss its potential Application. At its discretion, DOE may meet with a potential Applicant, either in person or electronically, to discuss its potential Application. DOE may provide a potential Applicant with a preliminary response regarding whether its proposed Application may constitute an Eligible Project.

One might reasonably assume that this would go without saying. Veterans of the project lending programs of other federal agencies like the US International Development Finance Agency (formerly OPIC) or the Export-Import Bank of the United States would probably expect that guidance through the application process would be a core responsibility of the program staff.

However, in the DOE loan guarantee program's first round of projects a decade ago, the loan programs office took a conservative approach to answering questions, / *continued page 18*

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be claimed on hydrogen made from natural gas, but only if all of the carbon emitted during production is captured and sequestered.

Construction of the hydrogen production facility would have to start by the end of 2026 to qualify for any tax credits. The production equipment would have to be put in service after this year.

The Treasury said the administration would work with Congress to impose "strong labor standards."

CARBON CAPTURE projects may get a boost in Canada.

The latest federal budget proposes adoption of an investment tax credit to encourage carbon capture projects, but the details are still being worked out.

The credit would take effect next year.

Canada captures about four million metric tons of carbon dioxide a year currently. It hopes a tax credit will help it increase the figure to 15 million metric tons a year.

The rate for the tax credit has not been set yet. Captured emissions could not be used for enhanced oil recovery, but rather would have to be buried underground.

The Department of Finance asked in early June for input about various issues that bear on design of the incentive. They include how large a tax credit is needed to get to 15 million metric tons of CO_2 captured and put in underground storage a year, what types of projects should qualify, and what financing structures are being used currently in Canada to finance such projects.

Comments are due by September 7.

THE TRUMP BULK-POWER SYSTEM ORDER that barred the purchase or use of any Chinese or other "foreign adversary" equipment that might be used to harm the US power grid has expired.

The Biden administration is assessing whether to issue a replacement.

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anxious to steer clear of any accusation that answering one applicant's question could provide that applicant an unfair competitive advantage over another applicant. A clunky process developed whereby applicants could submit questions and, if the question was deemed worthy, a carefully crafted answer would, after tiers of internal review, be posted publicly some weeks later among "frequently asked questions" on the DOE's website. An advantage of advising multiple clients in the application process was that external counsel could answer many of those questions based on the experience of other clients at later stages of the process. It was a terrific opportunity to add value as counsel, but, for applicants to a new federal financing program, the process was frustrating.

Today, the loan programs office staff is ready and able to answer applicant questions and provide reactions to potential technical, environmental and bankability issues posed by a project as well as to discuss the prospects for ultimate success even before the part I application is filed. There are no promises, of course, and assumptions and representations made in the applications need to be borne out through the diligence process, but the guessing game that characterized the program in the past should largely be avoided.

For those with past experience with the program, it is a new day.

Interest Spread

The all-in interest rate for a DOE-guaranteed loan will range from 0.375% to 2.0% above the interest rate for Treasury securities with a similar average life.

DOE introduced a "credit-based interest spread" in 2016 that is in effect a guarantee fee. It is added to a 37.5 basis-point "liquidity spread" charged by the Federal Financing Bank.

The DOE website says currently that the credit-based interest spread ranges from a maximum of 1.625% for a loan rated B- or below (although a loan with a lower rating is unlikely to pass muster under the program requirement of a "reasonable prospect of repayment") down to 0% for a project rated AA or better.

The credit-based interest spread should not be confused with another potential cost for applicants — the credit subsidy cost — but it will reduce the credit subsidy cost.

Under the Credit Reform Act of 1990, whenever the federal government makes a loan or issues a loan guarantee, it is required to put aside at the Treasury Department a loan loss reserve, inaptly termed the "credit subsidy cost." The amount is the projected loss to the government from having made the loan or guarantee. It reflects the projected net recovery for the government if the borrower defaults. The amount required to be deposited as the credit subsidy cost, which is calculated as a percentage of the loan commitment and is determined by a government model kept confidential, is only determined just prior to financial close. It must be deposited at financial close and cannot be funded with the proceeds of a government-guaranteed loan. If appropriated funds are not available to cover the loan's credit subsidy cost, it becomes a sponsor cost that could materially affect project economics.

This has not been an issue for any DOE-guaranteed loan to date. That is because all but one benefited from an appropriation under the American Recovery Act and Reinvestment Act in 2009 that covered each project's credit subsidy cost. The one exception was the Vogtle nuclear power project in Georgia. While DOE has generally kept credit subsidy cost calculations confidential, it became known that, thanks to high credit quality utility support, the Vogtle guarantee was deemed to qualify for a credit subsidy cost of 0%.

However, although a small amount of credit subsidy appropriation remains available for the title XVII program, future applicants will largely have to pay the credit subsidy cost out of their own pockets.

The credit-based interest spread will reduce the amount of credit subsidy cost applicants have to pay at closing. That's because the calculation takes into account projected future flows to the government, including projected payments of the credit-based interest spread.

When this new fee was conceived, there was some thought that it should substantially supplant the upfront credit subsidy cost payment. There appears to be less confidence of that now.

The program requires a credit rating for any project seeking a loan guarantee of more than $25 million. That rating is used to determine the credit-based interest spread. A preliminary rating is required to accompany the part II application and is confirmed (or adjusted) by the rating agency 30 days before financial close.

Stripping

If DOE guarantees 100% of a loan, then the "guarantee" is in effect a loan made by the Treasury Department's Federal Financing Bank.

The DOE loan guarantee program permits, and sometimes encourages or even requires a guarantee of less than 100%. For instance, the current tribal energy loan guarantee program offers guarantees only up to 90% of the guaranteed debt, so each transaction must be funded by a commercial lender that shares the risk of loss. Several of the largest loan guarantees provided after 2009 were pursuant to a financial institutions partnership program (FIPP). FIPP waived the innovation requirement, but limited DOE's guarantee to 80%.

While such risk sharing makes such partial guarantee programs more popular with Congress, they have a built-in inefficiency. There is no natural neighborhood in the capital market for 80%-government-guaranteed debt. A huge market exists for government securities, including fully guaranteed obligations, and lenders exist (albeit fewer) that are comfortable taking project risk. Obligations that are partially guaranteed but carry some project risk are unwelcome in the government obligations market and tend to find their way to lenders otherwise open to taking project risk. They welcome the partial guarantee but tend not to reward it with an interest-rate discount proportionate to the risk reduction.

An efficient solution, achieving the same policy goal, would be to issue fully guaranteed debt on condition that the borrower simultaneously raises a required amount of unguaranteed debt, but that is not what the statute or the regulations contemplate. A good fallback would be to permit the borrower to issue two classes of obligations into the capital market -— one fully guaranteed and one not at all. That bifurcation of the government support is referred to as "stripping." That was determined not to be an option for the partial loan guarantees issued under FIPP.

Several projects structured funding arrangements that both met the DOE restriction but pursued the benefit of placing obligations in their natural markets by stripping indirectly. The "lender" was a trust created to lend to the borrower in exchange for notes that were 80% guaranteed by DOE. The trust funded that loan by issuing two classes of debt, one fully covered by an allocation of DOE guarantee payments, and one eschewing any recourse to such payments. This works, but it generates transaction costs that made it attractive only to the largest transactions.

The revised DOE regulations now meet the market at least half way. Partial guarantees above 90% still cannot be stripped (except, presumably, as before, indirectly). But a guarantee up to 90% can be stripped, permitting the borrower in effect to issue fully guaranteed and fully non-guaranteed obligations, thus obviating the need to establish an intermediary trust.

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In the meantime, the US Department of Energy launched a 100-day joint effort in late April with utilities to try to harden the US utility grid against cyberattacks. The US energy secretary, Jennifer Granholm, warned in an interview on CNN on June 7 that foreign adversaries have the ability to shut down sections of the US grid.

The department issued a separate request for information on April 20 asking for recommendations by June 4 about how best to balance "national security, economic and administrability considerations" in any new order that is issued to replace the Trump order.

It warned that "the government of the People's Republic of China is equipped and actively planning to undermine the electric power system in the United States. The growing prevalence of essential electric system equipment being sourced from China presents a significant threat . . . ."

The Trump DOE issued a prohibition order on December 17, 2020 barring the purchase of Chinese-made transformers and related equipment by utilities serving critical defense facilities.

The Biden administration revoked the prohibition order on April 20 to buy time to decide on a new approach. The new request for information said that consideration is being given to extending the scope of the prohibition to distribution facilities — the prohibition order applied to equipment that connects to the grid at 69 KV or higher — and not limiting the order to equipment that serves critical defense infrastructure but rather extending it to equipment serving "national critical functions." (For earlier coverage, see "Trump bans certain power equipment" in the June 2020 *NewsWire* and "Trump bulk-power order stalled" in the February 2021 *NewsWire*.)

PRODUCTION TAX CREDITS for producing renewable electricity will remain at the same level this year as last year.

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DOE Lon Guarantees

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Other Terms

The DOE regulations have been amended to resolve several pending debates about what terms are permitted.

The regulations now provide that an eligible project:may be located at two or more locations in the United States if the project is comprised of installations or facilities employing a single New or Significantly Improved Technology that is deployed pursuant to an integrated and comprehensive business plan. An Eligible Project in more than one location is a single Eligible Project.

This question was not particularly in doubt since DOE has previously issued guarantees for at least two projects that involved multiple sites. However, the final sentence is important because applicants are tightly restricted as to the number of projects using a single innovative technology for which they can seek DOE financing. The regulations say the following:

Recent changes should make the program more user friendly.

An Applicant may submit only one Application for one proposed project using a particular technology. An Applicant may not submit an Application or Applications for multiple Eligible Projects using the same technology.

Thus, it is helpful to be assured that operations in multiple locations do not imply that more than one "project" exists for purposes of DOE financing.

The prior regulations said that the required credit subsidy cost had to be paid by the government or the sponsors, with the possible implication that it had to be paid wholly by one or the other. The regulations now make clear that the credit subsidy costs may also be paid from a combination of sponsor and government resources.

Another new provision clarifies that an eligible innovative technology may include a "defined suite of technologies."

Quirks remain. One is that DOE reserves the right to cancel the financing commitment for any reason and at any time prior to financial close. The principal mitigations of that risk are that DOE has never stood in the way of closing an otherwise approved guarantee and doing so either would be for thoroughly understandable reasons or would severely damage the credibility of the loan guarantee program. That is not a risk that at least this administration would likely take.

Postscript

Topping the good news may be developments in the loan guarantee program leadership and administration support.

The loan guarantee program has had sophisticated managers over the years, but has never before been led by an energy entrepreneur with a background in project development. The appointment of Jigar Shah, of Sun Edison and Generate Capital fame, puts in charge someone who has spent his career in the position of loan guarantee applicants. Shah's ability to look at the program from the applicant's perspective, plus the vocal support of US Energy Secretary Jennifer Granholm and the White House, should go far in energizing a program whose staff, for most of the past decade, could not be sure whether the program and their jobs would survive the next budget cycle. There are now good grounds for believing that the program is back. ◎

Virtual Supply Arrangements for Hydrogen Production

by James Berger in Los Angeles and Deanne Barrow in Washington

Companies that produce green hydrogen from electrolysis of water do not always have access to wind or solar energy near where the hydrogen will be produced. Similarly, companies that make green hydrogen from steam-methane reforming of renewable natural gas (RNG) do not always have access to RNG nearby.

In both cases, the hydrogen producer can enter into a virtual supply arrangement for the renewable electricity or RNG and still earn valuable credits under the California low-carbon fuel standard (LCFS). The contracts must be carefully structured, and the company must follow various other requirements.

This article discusses what a hydrogen producer should know if it wants to generate LCFS credits for hydrogen using a virtual feedstock supply.

Distant Feedstock

A green hydrogen company has two options for where to locate its production plant.

The first option is to co-locate the electrolyzer near the solar or wind project that will be a dedicated source of energy for the electrolyzer.

The main problem with this arrangement is that the best solar or wind resources are usually far from the potential demand for hydrogen, which is typically from industrial facilities in urban areas.

Hydrogen is not easy to transport. It has to be moved by truck or through pipelines. Both involve additional costs and logistical challenges. Dedicated hydrogen pipelines do not exist and will be expensive to build. There are ongoing studies investigating how much hydrogen can be blended with natural gas and transported in existing natural gas pipelines.

Another issue is the intermittency of solar and wind production. To reduce the cost of hydrogen as much as possible, the electrolyzer should have a high utilization. Connecting an electrolyzer directly to a solar or wind farm and producing hydrogen only when the sun shines or the wind blows increases the cost of the hydrogen, potentially making it uncompetitive with fossil-fuel hydrogen and other fuels.

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Refined coal tax credits will increase slightly.

Production tax credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) will remain 2.5¢ a kilowatt hour in 2021, the same amount as in 2020. They will remain at 1.3¢ a kilowatt hour for generating electricity from open-loop biomass, landfill gas, incremental hydropower and ocean energy.

The credits are adjusted each year for inflation as measured by the GDP price deflator. They run for 10 years after a project is originally placed in service.

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level for wind in 2021 is 13.5¢ a KWh. The IRS said there will not be any phase out in 2021 because contracted wind electricity prices were 3.59¢ a KWh going into 2021. It said it lacks data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $7.384 a ton in 2021. Refined coal is coal that has been treated with chemicals to make it less polluting than regular coal. The IRS said there will not be any phase out of refined coal credits in 2021. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2021 reference price is $45.64 a ton. A phase out would have started at $91.53 a ton.

The tax credit amounts were published in the *Federal Register* on April 27.

PARTNERSHIPS that own renewable energy projects should be able to sell electricity to one of the partners without causing loss of valuable tax depreciation, the US Chamber of Commerce said.

Under the US tax law, a company cannot claim a loss on a sale of property to an affiliate. Electricity is considered "property" for this purpose. Depreciation on most renewable energy facilities is

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Hydrogen

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The second option may be better. The developer can put the electrolyzer near the customer or customers for the hydrogen. The electrolyzer would not be directly connected to the solar or wind project that it claims as the source of electricity. Instead, it draws power from the local utility but signs a virtual power purchase agreement with a more distant solar or wind electricity supplier that is financially settled.

This structure is not new. Many companies that have bought large quantities of renewable energy (such as technology companies and big box stores) have done so by entering into virtual power purchase agreements. Such contracts allow the corporate buyer to say its facility is running on green energy and to lock in a fixed price for electricity that it would not otherwise have when relying on the local utility for power.

The main advantage of using a virtual supply arrangement to produce hydrogen is the lower carbon intensity of the overall production process. This allows the hydrogen producer to earn the maximum amount of LCFS credits.

The second advantage with off-site electricity production has to do with expertise. A hydrogen company is not necessarily in the business of solar or wind production. The converse is also true: solar and wind developers may not have expertise in hydrogen production. By decoupling the solar or wind project from the hydrogen project, different companies can be responsible for building different components of the facility, each sticking to its area of expertise.

The third advantage has to do with utilization. Solar or wind projects are frequently built at the hundreds-of-megawatts scale to take advantage of economies of scale. A hydrogen producer may not need to purchase all of the output. With a virtual supply arrangement, a hydrogen producer can purchase a portion of the output, with the remainder being sold to a different party.

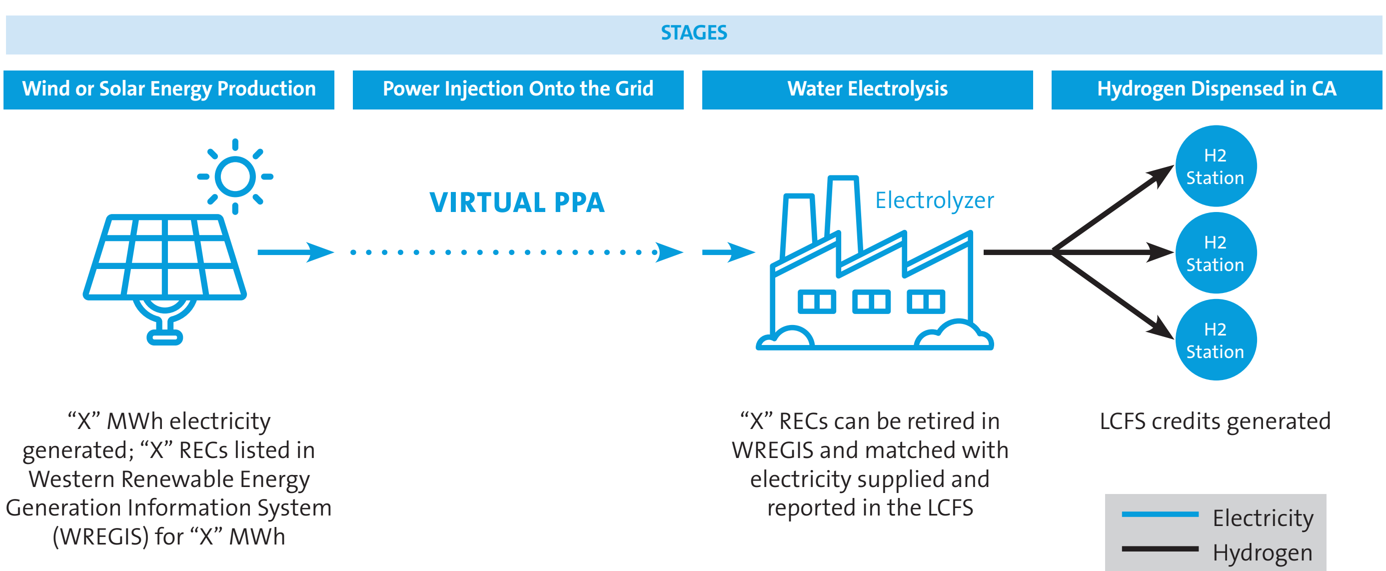
The same advantages also apply to hydrogen produced from off-site RNG. De-coupling the facilities allows the anaerobic digester to be built where a ready supply of biomass exists, while the steam methane reformer can be put close to the hydrogen customer. The steam methane reformer can be physically supplied by natural gas from an interstate or intrastate gas pipeline in California, but virtually supplied by the RNG facility in another state.

The LCFS regulations explain how to claim credits while relying on virtual electricity or RNG supply arrangements.

LCFS Background

Hydrogen producers and retailers can earn valuable credits under

Virtual Renewable Power Supply for H2 Production in California



Source: Norton Rose Fulbright

the LCFS to help cover the cost of projects. These credits can form the basis for a project financing. (See "Financing California hydrogen projects using LCFS credits" in the December 2020 *Newswire*.)

LCFS credits are awarded to suppliers of low-carbon-intensity transportation fuels in California to service stations and other retail or wholesale outlets. (The fuel needs to be sent to some facility or location where fuel is dispensed into vehicles, aircraft or ships.) The fuels must have a carbon-intensity (CI) score below the annual benchmark established by the California Air Resources Board (CARB).

There are three ways to qualify for credits under LCFS. One is through pathways-based crediting under which a supplier of hydrogen directly to service stations or other retail or wholesale outlets receives credits by obtaining a certified CI score and reporting the quantity of fuel put into motor vehicles on a quarterly basis. The CI score depends on the production process, called the "fuel pathway," used for converting feedstock into a finished fuel.

A fuel pathway that uses renewable electricity to produce hydrogen from water provides the maximum amount of LCFS credits. Similarly, a fuel pathway that relies on RNG to produce hydrogen provides more credits than one relying on fossil-based natural gas.

Renewable Electricity

A hydrogen company can power its electrolyzer using electricity from the local utility, but still report the use of 100% renewable electricity in its LCFS fuel pathway application if a number of requirements are met.

The first requirement is for the LCFS applicant to show that the electricity was generated by it, or supplied to it under contract, and it is entitled to all the environmental attributes of the claimed electricity. The applicant must make its power purchase agreement available to CARB upon request.

Generation invoices or metering records must be made available to substantiate the quantity of renewable electricity produced. Monthly invoices must be un-redacted and show the electricity purchased in kilowatt hours and the contracted price.

The electricity usually must be supplied to the grid within a California balancing authority or, for hydrogen produced outside of California, the local balancing authority.

However, hydrogen producers should bear in mind that they may report the renewable electricity within only a three-quarter time span. If a renewable electricity / *continued page 23*

IN OTHER NEWS

taken on a front-loaded basis over five years. Most wind and solar projects report tax losses at least through the first three years. They are considered to generate electricity during this period at a loss.

Electricity from many projects is sold into an organized spot market. Such projects cannot be financed currently unless there is a hedge or other arrangement to put a floor under the electricity price. One way to put such a floor under the price is for the project developer to enter into a back-to-back arrangement where it buys electricity from the project for a fixed price and then resells it into the spot market. However, section 707(b) of the US tax code will prevent the partnership from claiming net losses during whatever period the project is running a net loss due to depreciation. Therefore, such back-to-back arrangements are usually structured as swaps so that there is no electricity "sale."

The IRS has declined in private letter rulings to say that section 707(b) does not apply where there is an actual sale. (For a recent example, see "Utility partnership flips" in the June 2020 *NewsWire*.)

The IRS is collecting comments about issues it should address in its next priority guidance plan for the period July 1, 2021 through June 30, 2022. The Chamber asked the IRS in a letter at the end of May to put the issue on the list.

OPPORTUNITY ZONES are not attracting much investment in power projects.

Only $10.9 million of the $15.7 billion invested in such zones in 2019 by investors filing their federal income tax returns electronically was invested in "utility" assets.

The figures are in a background document that the Joint Committee on Taxation staff prepared for a House hearing in late May on leveraging the tax code to encourage infrastructure investment.

There are more than 8,700 low-income areas in the United / *continued page 25*

Hydrogen

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quantity is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity used for hydrogen production no later than the end of the third calendar quarter. After that period ends, any unmatched renewable electricity quantities expire for the purpose of LCFS reporting.

The second requirement prevents double claiming of benefits associated with the "green-ness" of the electricity. Any renewable energy certificates (RECs) or other environmental attributes associated with the electricity must be retired and cannot be claimed under any other program. The quantity of RECs retired must correspond to the aggregate electricity quantities reported quarterly to CARB.

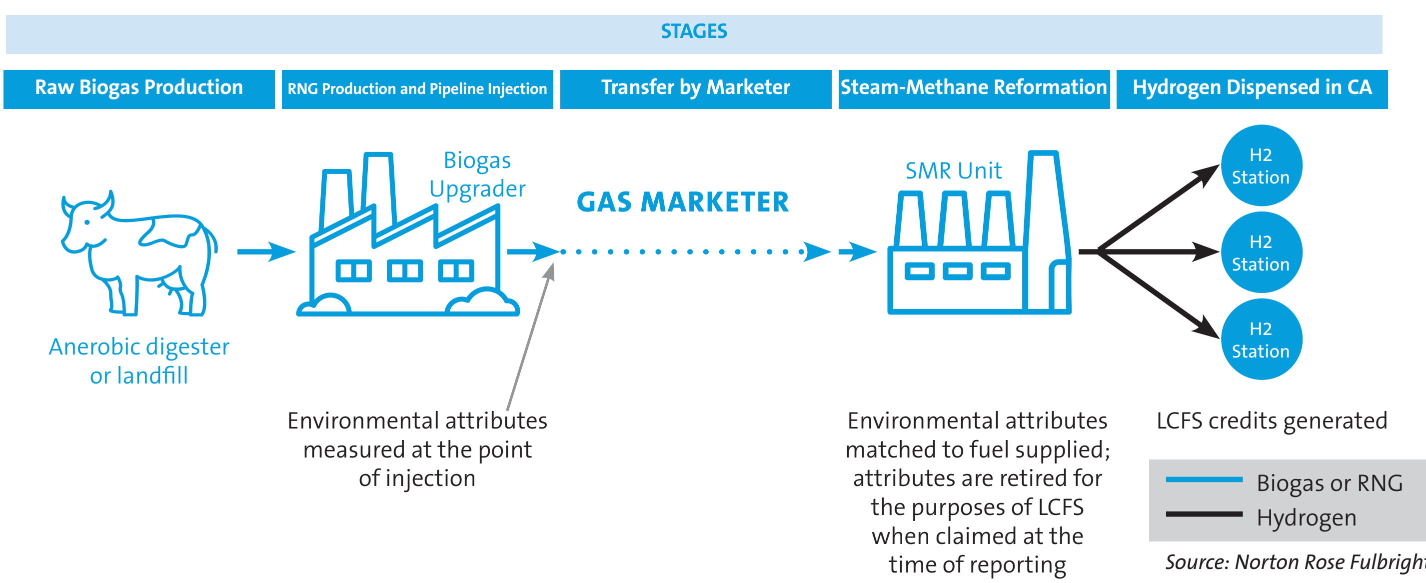
However, there are two exceptions. The electricity can be claimed for the federal renewable fuel standard operated by the Environmental Protection Agency and for California's cap-and-trade program (provided that the electricity is not claimed in the cap-and-trade program's voluntary renewable electricity program).

The third requirement has to do with additionality. Any electricity procured by a utility, community choice aggregator or other load-serving entity for the purpose of claiming a lower carbon intensity must be in addition to that required for compliance with the California renewables portfolio standard (RPS) or, for hydrogen produced outside of California, in addition to local renewable portfolio requirements of the state where the utility is located.

In California and several other western states and territories, RECs are issued and tracked in an online system called the Western Renewable Energy Generation Information System (WREGIS). Utilities and other load-serving entities can use or "retire" RECs in the WREGIS to demonstrate compliance with RPS procurement requirements to which those entities are subject. However, if the electricity is being used for electrolytic hydrogen production, then the hydrogen producer must retire the RECs in the WREGIS for the express purpose of generating LCFS credits. Doing so will remove the RECs from circulation and prevent a utility from counting the RECs toward RPS targets.

If any of these three requirements is not satisfied, then the project must demonstrate that energy from the renewable source is directly consumed to produce hydrogen. This requires the solar or wind project to connect directly to the electrolyzer through a dedicated line such that the generation and the load are both physically located on the customer side of the utility meter. This may be possible where the solar or wind electricity is sold to the grid, but there is still a direct line between the solar or wind project and the electrolyzer.

Virtual RNG Supply for Green H2 Production in California



Source: Norton Rose Fulbright

RNG

The LCFS regulations also specifically address the use of distant RNG.

Instead of physically supplying the RNG directly to the electrolyzer, the RNG counts toward LCFS requirements if it is injected into a common carrier pipeline in North America even though it ends up comingled with fossil natural gas.

There are two requirements for this to work.

The first requirement is for the LCFS applicant to substantiate RNG quantities injected into the natural gas pipeline system. The hydrogen producer must demonstrate a link between the environmental attributes of RNG, measured in mmBtus or therms, with corresponding quantities of natural gas withdrawn. It must provide CARB with un-redacted monthly invoices showing the quantities of RNG purchased and the contracted price per unit, as well as the un-redacted contract by which the hydrogen producer obtained the environmental attributes.

Like in the case of grid electricity, RNG purchased counts only if it can be matched to RNG used to produce hydrogen within a three-quarter time span. If a quantity of RNG is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter. After that, any unmatched RNG quantities expire for the purpose of LCFS reporting.

The second requirement is that the hydrogen producer must give CARB an attestation regarding environmental attributes. The attestation states that the producer owns the exclusive rights to the corresponding environmental attributes and has not sold, transferred or retired those environmental attributes in any program or jurisdiction other than the federal renewable fuel standard or the California cap-and-trade program. The applicant must also have confirmatory attestations from each upstream party in the RNG production chain and make them available to CARB upon request. ◎

IN OTHER NEWS

States that have been designated as opportunity zones. The US government has made a limited-time offer to investors with large capital gains to try to get them to invest in such zones. The offer has two parts.

Part one is the government will wait to collect taxes on capital gains that are reinvested in a business inside an opportunity zone until the end of 2026. When the taxes are ultimately collected, the government will tax only 90% of the reinvested gain if the new investment in the opportunity zone has been held, by 2026, for at least five years, and it will tax only 85% if the new investment has been held, by 2026, for at least seven years.

Part two of the offer is if the new investment in the opportunity zone is held for at least 10 years, then the government will not tax any gain on the *new* investment when it is sold.

Opportunity zones have been a disappointment so far to renewable energy developers. Some developers were hoping they would be a source of equity capital after the opportunity zone provisions were enacted in late 2017. However, tapping into the capital flowing into such zones has proven difficult. The IRS opportunity zone regulations read like an intricately structured maze. The zones work best for real estate projects. They are harder to make work for investments in operating businesses. (For more detail, see "Opportunity zones and renewable energy" in the June 2019 *NewsWire*.)

UTILITY CONTRIBUTIONS to a state fund to cover damages after a weather event create an intangible property right.

The utility can deduct the cost ratably over 15 years, the IRS said in a private letter ruling made public in May.

The ruling is Private Letter Ruling 202119007.

It appears to address a fund that California established in 2019 to deal with damages caused by wildfires. The fund is capitalized partly by the state and / *continued page 27*

States Move to Price Carbon

by Ben Grayson in New York and Matthew Gurch in Washington

The debate in the United States about whether to put a price on carbon emissions overlooks the fact that states covering a quarter of the US population and a third of the US economy already put a price on such emissions.

Washington State enacted a new "cap-and-invest" plan in May that is supposed to reduce carbon emissions in the state by 45% by 2030, 70% by 2040 and 95% by 2050.

The plan will take effect in 2023, provided the state enacts a separate transportation-spending package that increases the gas tax by at least 5¢ a gallon.

Washington is now the third US state effort to tackle carbon emissions without waiting for the US government to act. The other two are a 16-year old regional effort by the New England and mid-Atlantic states called the Regional Greenhouse Gas Initiative — or RGGI — and an ambitious eight-year old California program that is linked to Quebec.

The state efforts give factories that generate their own electricity using natural gas, coal or types of biomass that satisfy eligibility requirements an incentive to buy electricity instead from renewable sources rather than have to pay for allowances to cover their carbon emissions.

Carbon emission allowances cleared the latest RGGI auction on June 2 at $7.97 a ton and were priced in California at $18.80 a ton as the *NewsWire* went to press. The price for allowances in Washington state is still unknown, but the state is projecting revenue from allowance auctions of approximately $480 million in the first year of trading in 2023 and up to $580 million by 2040.

Companies that generate electricity using fossil fuels or certain types of biomass spent $416.3 million in 2020, the most recent year for which such data is available, on allowances to cover their carbon emissions in the 11-state area covered by RGGI.

The figure for California was $1.7 billion in 2020.

A monitoring report released by RGGI in March 2021 showed that the annual average carbon emissions rate among RGGI electric generation sources decreased by 31.4% between 2016 and 2018 as compared to the base period of 2006 to 2008. A 2020 report on the California program showed that the state reduced annual greenhouse gas emissions by 4.98% in 2018 as compared to 2013 when the cap-and-trade plan took effect.

Washington

The details of the new Washington state plan are in the "Climate Commitment Act," also known as SB 5126.

The governor and state legislature acted after voters failed in a ballot initiative in 2018 to impose a fee on carbon emissions.

The carbon reductions will be helped by two other state laws — one that requires a phase-out of carbon pollution from state power generation by 2045 and another that creates a clean fuels standard for marketers of gasoline and diesel.

There is no sunset or time limit on the Climate Commitment Act. It will stay in place until the state achieves net-zero emissions, which will avoid political battles over reauthorization.

The main feature of the new plan is a mechanism being called "cap and invest." The plan sets annual pollution and allowance limits for entities that emit at least 25,000 tons of energy, process or landfill emissions per year. This threshold covers roughly the state's 100 largest greenhouse gas emitters.

The number of allowances is linked to electricity supply and demand forecasts. The overall pool of carbon allowances will be gradually reduced over time in order for the state to achieve its 2050 net-zero emissions goal. A declining cap should force emission reductions. The theory is that as allowances become more scarce and expensive, emitters will have an incentive to make investments to reduce their

A third of the US economy is in states that have put a price on carbon emissions.

emissions rather than have to pay more for allowances to cover their emissions.

The state will distribute allowances in three ways: auctions, direct allocation to industrial companies and direct allocation to utilities.

Most of the allowances will be auctioned to emitters and auctions will occur four times a year. The state will set a floor-to-ceiling price range for auction bids in order to protect the program from price shocks.

The ceiling will take the form of an allowance price containment reserve. This means that if the allowance price hits the ceiling, unlimited allowances at that price can be released from a reserve until prices go back down.

There will also be an emissions containment reserve, set to a trigger price that will allow the state to withdraw subsets of allowances from the system if the emission targets are not being met. The state will set the floor, ceiling and trigger prices through rulemakings and revisit pricing on certain predetermined milestone dates. However, the state can also revisit pricing and the number of allowances in the system at its discretion.

At the outset of the allowance program, a regulated source will have to hold one emission allowance in order to emit one ton of carbon dioxide equivalent. Large emitters may engage in secondary trading of pollution allowances.

Certain electricity generators, like smelters or factories that are considered vulnerable to out-of-state competition, will get most of their allowances for free, at least through 2035.

Free distribution of allowances to industrial emitters is being done to prevent leakage of businesses and pollution to other states with more lax regulation of greenhouse gas emissions.

Consumer-owned and investor-owned utilities in the state will be given allowances in an effort to prevent ratepayers from having to pay more for electricity.

If utilities reduce emissions ahead of schedule, they can auction off the remainder of their allowances. Local gas distribution companies will get free allowances equal to their emissions for the first year of the program, after which the number of allowances they are issued will decline by about 6.5% a year through 2030, which is the rate at which the carbon emissions cap drops annually. Starting in 2023, local gas distribution companies must make auction sales of 65% of their free allowances, with that figure rising by 5% a year until it reaches 100%.

The state Department of Ecology will collect annual, verified greenhouse gas emissions data from each covered entity to verify compliance. The data will be used to / continued page 28

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partly by contributions by participating utilities. Each participating utility had to make an initial contribution and then make ongoing annual contributions for an agreed period.

The IRS said the fund will be used to reimburse participating utilities for any "eligible losses" as defined in the state statute creating the fund.

Companies can deduct costs of doing business. Such costs can be deducted currently unless the spending creates an asset that will last more than a year, in which case the cost must be capitalized into the asset basis and recovered through depreciation or amortization.

Amounts set aside to pay damages are not usually deductible until the damages have to be paid.

In this case, the contributions bought the utility a form of liability shield and the possibility of recovering some of its losses from the fund. (For more detail on now the California wildfire fund works, see "California moves forward" in the October 2019 *NewsWire*.)

The IRS analogized the contribution to a payment for a government permit or license that the US tax code treats as a "section 197 intangible" whose cost can be recovered ratably over 15 years. IRS regulations offer the following other examples of rights that fit in this category: "a liquor license, a taxi-cab medallion (or license), an airport landing or takeoff right (sometimes referred to as a slot), a regulated airline route, or a television or radio broadcasting license."

The IRS said the initial contribution can be deducted ratably — meaning in equal amounts — over 15 years. It said the subsequent contributions can be recovered ratably over the remainder of the original 15-year period.

CORPORATE SHAREHOLDERS must pay an additional 3.8% tax on dividends, the IRS said in an internal memo made public in May.

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Carbon

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determine how many allowances each entity needs to turn in for compliance purposes. Entities will turn in any allowances they have been given or purchased to cover their emissions. An entity that fails to turn in the required amount of allowances will be required to turn in four allowances for each ton of greenhouse gases it emitted during the relevant period. This penalty is a strong incentive to buy the right amount of allowances.

The auction proceeds collected by the state will be deposited in new accounts set up to direct cash toward greenhouse gas reduction initiatives. These initiatives are wide ranging. They cover measures related to reducing transportation-related greenhouse gas emissions, financial support for biofuels, biomass and manure digesters at dairy farms, energy storage, energy conservation, other measures to reduce emissions in the agriculture sector, electrification and decarbonization of buildings, support for workers to transition to new jobs in the clean energy and decarbonization sectors, carbon sequestration, mitigating the impact of climate change on the state's forests, estuaries, oceans, fisheries and other ecosystems, and reducing pollution and health disparities in disadvantaged communities.

The Washington state plan also allows a small number of "offsets" to be used for compliance purposes.

An offset is a credit for activities that reduce greenhouse gas emissions outside of capped sectors.

Covered emitters may meet 8% of their compliance obligations through carbon offsets in the first compliance period that runs from 2023 through 2026. From then on, the offset cap is 6%. In order to receive an offset, the emission reductions must be permanent, verifiable and proven to have not otherwise happened.

The state will reduce the total amount of allowances issued each year to make up for the allowed level of offsets to ensure that the overall amount of allowances and offsets together does not exceed the level of the emissions cap.

The use of offsets is fairly constrained, requiring that at least half of offsets come from activities that provide direct environmental benefits to Washington state, and the law includes specific set-asides for offsets from Indian tribes.

RGGI

RGGI is a regional effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia to reduce greenhouse gas emissions by the power sector. The initiative started in 2005 and auctioned its first group of emission allowances in 2008.

Virginia joined last year and Governor Tom Wolf is pressing for Pennsylvania, the biggest energy producer on the East Coast, to join RGGI as early as 2022. However, opponents in the Republican-controlled general assembly are currently pushing through legislation that, if passed, would effectively block Pennsylvania from joining RGGI.

RGGI requires fossil-fuel-fired electricity generators with a capacity of 25 megawatts or greater to hold at least one allowance for each short ton of CO_2 aggregate emissions over each three-year control period. More specifically, these generators must hold allowances equal to at least 50% of their emissions during each of the first two calendar years of each three-year control period. Compliance is evaluated at the end of each three-year control period.

New York requires RGGI compliance by electricity generators with capacities of 15 megawatts or greater if a generating unit is located near one or more other generating units under common ownership with capacities of 15 megawatts or greater.

The total number of available allowances is determined based on the emission reduction goals for the RGGI region as a whole. RGGI plans on reducing the total number of allowances by 30% between 2020 and 2030.

Generators may acquire allowances either through quarterly allowance auctions or on secondary markets.

Quarterly auctions are sealed-bid, uniform-price auctions that are open to all qualified participants and result in a single, quarterly clearing price. Secondary markets include both over-the-counter trades and exchanges, such as the Nodal Exchange and the ICE NGX and Intercontinental Exchange.

Similar to the Washington state plan, RGGI auctions are subject to both a price ceiling, in the form of an allowance price cost containment reserve that releases additional allowances as a safety valve to hold down prices, and a price floor, in the form of an emissions containment reserve that withdraws allowances when the price has fallen too far to leave much incentive to control emissions.

In 2021, the price trigger for the containment reserve is $13 and the price trigger for the emissions containment reserve is $6. These thresholds will increase by 7% a year. The emissions containment reserve price floor does not currently apply to power producers in Maine or New Hampshire.

Generators in Connecticut, Delaware, Maine, Maryland, New

Jersey, New York and Vermont may also obtain a limited amount of allowances through permitted offsets. These offsets give credit toward a generator's available emission allowances in a specific RGGI state for its emission reductions in another RGGI state.

An important caveat is that the offsetting power plant must be located within a RGGI state that also awards offset allowances. For example, a New York power producer cannot take advantage of emission reductions for its other projects in Massachusetts, New Hampshire, Rhode Island or Virginia. Moreover, offset allowances are capped at 3.3% of a power plant's emissions for any applicable control period. Few generators actually use these offsets due to the relatively low price of allowances available through the quarterly auctions.

California

The California program launched in 2013 and limits emissions of six types of greenhouse gas emissions in the power and industrial sectors. It was expanded in 2015 to cover transportation fuels and natural gas.

The California Air Resources Board enforces the program. Any electricity generator that emits at least 25,000 metric tons of greenhouse gases a year is covered. Electricity that a generator imports into California counts toward the 25,000.

The approach of capping emissions in multiple sectors makes the program broader than RGGI and more akin to the Washington state program.

Like RGGI, the compliance evaluation for California generating sources takes place at the end of each three-year control period. California's overall goal is to reduce its greenhouse gas emission cap by 5% a year from 2021 through 2030.

Emission allowances are distributed through a mix of free allocation and quarterly auctions. The portion of emissions covered by free allowances varies by sector. The number of free allowances is set by regulation and often function to grandfather politically sensitive industries that might otherwise relocate to other states. The portion of emissions covered by these free allowances also depends on the efficiency of the relevant facility when compared to industry benchmarks.

California's auction mechanics are similar to the mechanics in Washington state and RGGI: they include a sealed-bid, uniform-price auction that is subject to both a price ceiling and a floor.

At the beginning of 2021, a hard price ceiling of $65 per metric ton was set and will increase by 5% annually (plus an inflation adjustment), and an unlimited supply of */ continued page 30*

IN OTHER NEWS

The US began collecting an extra 3.8% tax in 2013 from individuals on "net investment income" to help fund a Medicare expansion. The tax is in section 1411 of the US tax code. It applies to most interest, dividends, capital gains, rents and royalties received by individuals and to other income from any business conducted through a partnership or other pass-through entity in which an individual is considered a passive investor. (For more details, see "A new US tax on investment income" in the February 2013 *NewsWire*.)

The IRS discovered on audit that a corporation was paying personal expenses of its majority shareholder. It treated the payments as dividends to the shareholder. The IRS office in Los Angeles, where the shareholder is located, asked for advice from Washington whether the shareholder had to pay not only regular income taxes but also the 3.8% tax on the dividend. The IRS national office responded "yes" in an internal memo. The memo is CCA 202118009.

The shareholder argued that he should not be subject to the extra tax because he was not a mere passive investor. He worked more than 500 hours a year in the business as an employee of the company. The IRS said his personal involvement with the business would be relevant only if the business were a partnership rather than a corporation. The tax must be paid on all dividends.

The tax applies to anyone earning more than $250,000 a year in adjusted gross income for married couples filing joint returns. The threshold is $200,000 for single persons. The income levels are not adjusted for inflation, so more people will become subject to the tax over time.

— contributed by Keith Martin in Washington

Carbon

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allowances will be available at this price.

California's program is linked with Quebec whereby offsets and allowances can be traded across the two jurisdictions, providing greater liquidity for these assets.

Similar to the Washington state and RGGI programs, California allows emitters to use certain offsets to make up emissions allowance shortfalls. These offsets are capped 4% of an electricity generator's total emissions for 2021 through 2025 and 6% for 2026 through 2030. Beginning in 2021, at least half the offsets used for compliance must come from projects that directly benefit California. ◎

Inbound US Investment Structures for Renewable Energy

by Keith Martin, in Washington

Interest among foreign investors in US renewable energy projects and development platforms remains strong, especially from investors in Canada, Europe, Japan and South Korea.

An issue for non-US companies investing into the United States is how to structure the investments.

The answer depends on the particular facts, but a good default position is the following:

Invest through a Delaware limited liability company that acts as the US holding company. Consider whether to have a separate Delaware LLC for each project in cases where the investor may want to shed individuals projects in the future while retaining others.

File a form with the US tax authorities within 75 days after the Delaware LLC is formed to treat it as a corporation for US tax purposes.

Take care in what order assets accumulate in the LLC. Make sure that at no point is 50% or more of the asset value in assets that are considered US real property. Consider capitalizing the company by lending part of the investment rather than putting in the full investment as equity.

View this default position as a working hypothesis. Test whether the overall tax burden not only in the United States, but also in the home country of the investor, can be reduced by tweaking the structure.

This article is aimed more at foreign companies and investment funds investing in the United States than individual investors. Many of the basic principles are the same, but there are additional complications — and opportunities — for individual investors. (One of the more frustrating truths about the US tax laws is that the rules are often more complicated for individuals than for large corporations.)

Initial Challenges

Europeans warmed more quickly to renewable energy than the Americans did. European companies built up impressive early experience with wind and solar projects and new storage and hydrogen technologies. When demand for renewable energy began to grow more rapidly in the United States in the early 2000s, Europeans initially found several things daunting about the US market.

One was the complexity. Each of the 50 states and the District of Columbia, an enclave where the national government is based, has its own public utility commission that regulates electricity supply, and each has its own tax rules. Taxes at the federal level can reach close to 45% on the operating earnings that a foreign investor might earn from a US project, and there are additional state and local taxes to pay.

The other issue was that the US government subsidizes renewable energy projects heavily through the tax code. The federal government pays currently as much as 44¢ per dollar of capital cost of renewable energy projects through tax subsidies. New foreign entrants come without a US tax base. This puts them at a disadvantage when trying to compete with the incumbent US utilities.

However, they soon realize that regulated utilities are not the main competition. Most renewable energy development is by unregulated independent power companies, few of whom can use the subsidies either. Most of these developers essentially barter the tax subsidies to large banks, insurance companies and other "tax equity" investors in exchange for capital to pay part of the cost of their projects. There are more than 40 tax equity investors and three basic tax equity structures in use, with many variations on the basic structures, although the tax equity market is highly concentrated with just two big banks accounting for more than half the market volume.

US Holding Company?

It is usually better to hold US investments through a US holding company than to invest directly from abroad. There are at least three reasons.

First, investing directly will cause the foreign company or investment fund to be considered engaged in a US trade or business and require it to file US tax returns as if it were an American company.

US renewable energy projects are almost always owned by special-purpose limited liability companies that are transparent for tax purposes, meaning there is no US income tax at the project company level. This allows tax subsidies on the projects and earnings to pass through to the owners of the project company. It is important for being able to raise tax equity to help finance the project.

A foreign company or investment fund investing in such a transparent entity will be considered engaged directly in a US trade or business and become subject to US income tax at a 21% rate on its share of net income earned by the project company. The foreign owner will have to file US tax returns. It will be taxed on its share of income whether or not any cash is distributed to it. If the project company has more than one owner, then the project company will be treated for US tax purposes as a partnership and be required to withhold income taxes on the share of its net income that is allocated to foreign owners.

Second, investing directly from abroad will also subject the foreign company or investment fund to a "branch profits tax" in the United States that is collected in theory at the US border on any earnings that the foreign owner brings home, but that will be levied in practice without waiting for earnings to be repatriated.

Most countries collect two taxes on earnings: there is an income tax inside the country and a withholding tax at the border on dividends, interest and other payments across the border. The US withholding tax rate is 30%, but it is often reduced or waived entirely by bilateral tax treaties between the United States and other countries.

The United States started imposing a separate branch profits tax in 1986 on foreign companies that engage directly in business in the United States. Such companies escape US withholding taxes since earnings are repatriated to the head office merely by transferring them within the foreign corporation and not by paying a "dividend." The branch profits tax rate is the same as the withholding tax rate, but the main problems are that it is more difficult to control the timing and the tax is more complicated than the withholding tax to calculate. (US tax treaties that reduce withholding tax rates usually also reduce the branch profits tax rate, but it is important to check. Older tax treaties that were in effect before 1986 may prevent the US from collecting branch profits taxes.)

Branch profits taxes are collected on the "dividend equivalent amount," meaning the earnings and profits the foreign company had from US business operations from which it could have paid a dividend. The amount is increased to the extent the foreign company had a lower net investment in the US business operation at the end of the year than when the year started. It is reduced to the extent the foreign company had a larger net investment in the US business operation at year end. The net investment is calculated by subtracting any debt related to the US business operation from the adjusted basis that the foreign company has in the assets used in that business.

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Unless significant capital additions are being made, the net equity will usually draw down as the existing assets depreciate.

Third, direct investment could also make it more expensive to exit the investment later.

The United States does not tax foreigners on their capital gains when US investments are sold, with one major exception. Congress became concerned in 1984 about growing Japanese investment in US farmland. The concern was that this would bid up prices and make it harder for smaller family farms to survive. It was too hard to define farmland, and so Congress ended up requiring that foreigners pay taxes on sales of interests in any "US real property." Part of any renewable energy project is considered real property. However, even if none of it were, the gain a foreign company receives from sale of an interest held directly in a US partnership is "effectively connected" income, meaning it is subject to net income taxes at a 21% rate. [The foreign company will be taxed this way on the lesser of its gain or the share of gain the foreign company would have had to report as a partner if the partnership had sold all of its assets and liquidated.]

One way to avoid a tax on exit is to hold the partnership interest or project through a US holding company that is treated as a corporation for tax purposes. Shares in the corporation can normally be sold without having to pay a US tax on the gain.

The ideal US inbound investment structure for foreign investors starts with a blocker corporation.

Care must be taken to avoid turning the US holding company into a "US real property holding corporation." It will be considered a holding company for real estate investments if at least half its total assets by market value are interests in US real property. Once the company becomes tainted with this label, then the taint will last for at least five years. Its assets are tested on numerous "testing dates."

The developer of a renewable energy project often signs an option to buy or lease a site as one of the first steps in the development process. In the case of a wind farm, the developer erects a meteorological tower and monitors the wind speed on the site for at least one to two years. Other early steps in the development process are to get in line to connect the project to the utility grid, obtain permits to build and negotiate a long-term contract to sell the electricity from the project to a nearby utility.

It is important not to put the development assets under the holding company while 50% or more of the value is in the site. The US independent power industry takes the position that a site lease has value only to the extent the rents the developer is required to pay are below market. Its position is that a power contract has value only to the extent that the electricity prices are above market, so other contracts may not have much offsetting value beyond the cost to put them in place.

Delaware LLC

It is usually best to use a Delaware limited liability company as the US holding company.

Delaware has the most well developed body of corporate law among all the states, except possibly New York. Its limited liability company statute allows flexibility in terms of business arrangements among the owners. Most US lawyers at the larger US law firms are familiar with the Delaware statute; they are not as familiar with statutes in other states. This has sometimes led to situations where developers who have formed project companies in other states have had to reorganize them in Delaware before banks and tax equity investors will provide financing.

A limited liability company is like a corporation in that its owners are shielded from liability for the company's debts, but it has a lot more flexibility in terms of permissible business arrangements. It can function like a corporation with a board of directors, officers and periodic dividends to shareholders, or it can operate like a partnership where the members run the business directly and agree to changing ratios over time for distributing earnings.

Unlike a corporation, the owners can choose how they want a limited liability company to be taxed. An election should usually be filed with the Internal Revenue Service within 75 days after the limited liability company is formed to treat it as a corporation for US tax purposes. The election is filed on Form 8832. The form is available on the IRS website at www.irs.gov.

The reason for filing within 75 days is that is the period that the election can relate back. The owners are free to change their minds later about the tax classification if the LLC has been a corporation from inception; otherwise, they are locked into the elected status for five years. If no election is filed, then the LLC will be treated as a partnership for US tax purposes, if it has more than one owner, or as a "disregarded entity," if it has only one owner. A "disregarded entity" is ignored. It is treated for US tax purposes as if it does not exist.

Single Holding Company?

A separate holding company for each investment will allow more options when it comes time to exit a project. One project can be sold without having to sell others.

However, there is a tradeoff. Renewable energy projects in the United States usually do not start generating taxable income until three to four years after a project has started operating because of the large amounts of tax depreciation and tax credits to which the owner is entitled. The owner is better off using this tax shield himself if he has other income that can be sheltered with it rather than bartering it in the tax equity market where he will get less than full value for it.

Using a single holding company for all projects will eventually create a tax base against which the tax shield can be used.

A consolidated US income tax return cannot be filed for a series of separate US holding companies. Corporations can join in filing a consolidated return only if they are at least 80% owned by vote and value by a common US parent company.

It may be possible to get the benefits of consolidation while keeping separate US holding companies for each project by having whichever holding companies are earning taxable income enter into tax equity transactions with project companies that have just put new projects in service. These "cross-chain" tax equity transactions raise a number of tax issues that require careful consideration and are beyond the scope of this article.

Other considerations may come into play. For example, the foreign company may put employees on the ground in the United States. They may have responsibility for business operations not just in the United States, but also in Canada and Mexico or even into Central and South America. Depending on the nature of the business, it may make sense for administrative convenience to put all the western hemisphere operations under a single US holding company, but to make that holding company a disregarded Delaware limited liability company that sits atop separate subsidiary holding companies for each project in the United States and for business operations in each of the other countries.

However, the US employees should stay in one of the subsidiary US holding companies. Making them employees of the disregarded umbrella holding company would cause the foreign parent company to have a "permanent establishment" in the United States. Since the umbrella company does not exist for US tax purposes, whatever it does is treated as done by its foreign parent company directly. Under US tax treaties, business profits of a foreign entity cannot be taxed in the United States unless attributable to a permanent establishment of the foreign entity in the US.

A portion of the profits earned by the foreign parent could be attributed to the permanent establishment under US attribution rules.

Accumulating Assets

Care should be taken about the order in which assets accumulate under the US holding company for each project.

Developers of US renewable energy projects usually secure an interest in a site for the project at an early stage the development process. At no point should 50% or more of the value be in assets that are considered interests in US real property.

The asset mix of the holding company will be tested on a series of "testing dates." The testing dates include the last day of each tax year of the holding company, and each day that an interest in US real property is acquired or sold. Once the holding company is tainted, the taint will last for at least five years. A tainted company is called a "US real property holding corporation." Paying attention to the asset mix will make it more likely that the foreign company or investment fund can sell its interest in the project in the future without having to pay US taxes on its gain.

Any such sale would have to be of shares in the US holding company. As long as the holding company is not tainted, then no US tax will have to be paid on the gain. */ continued page 34*

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If a tax is owed, then the gain will be treated as "effectively connected" income from a US trade or business, and will have to be reported by the seller by filing a US tax return. It will be subject to taxes not only at a 21% federal rate, but also to a branch profits tax. However, rather than take chances, US law requires the buyer to withhold 10% of the gross purchase price. The seller can get back any excess taxes it paid on its actual gain by filing a US tax return.

If the holding company is tainted by having owned too much US real property in the last five years, then it may be better to sell its assets and liquidate the holding company rather than sell shares in the holding company directly. The holding company will be subject to US income taxes at a 21% rate on the asset sale, but there will usually not be any further withholding or branch profits tax to distribute the sales proceeds to the foreign owner.

However, there is a risk of an "accumulated earnings tax." US corporations that accumulate significant earnings rather than pay dividends are exposed to a penalty tax at a 20% rate. The tax is imposed at the corporate level. The aim of the tax is to prevent corporations from waiting to pay dividends until a shareholder has losses that can be used as shelter or not paying dividends at all to enable individual US shareholders to convert them into capital gains at lower tax rates or foreign shareholders to avoid taxes altogether by eventually selling the corporate shares. The tax is infrequently imposed. It requires the IRS to substitute its business judgment for the judgment of corporate management by concluding that the corporation allowed earnings to accumulate beyond the reasonable needs of the business.

Another strategy to avoid a tax on exit is to sell shares in a foreign entity treated as a corporation for US tax purposes that owns shares in the US holding company. The US tax net does not reach such a sale.

While the strategy of using a separate US holding company for each project and electing to treat it as a corporation gives a foreign company a way to exit US projects directly without having to pay US tax on gain, the foreign owner may find it hard to arrange such an exit in practice. The exit requires selling shares in the US holding company rather than selling the interest it holds in the US project company. Other things being equal, buyers prefer to buy assets.

One reason is fear of unknown liabilities in the corporate holding company, including the possibility that the holding company joined at some time in the past with other corporations in filing a consolidated return at the federal level or combined return at the state level. In such cases, the holding company may be subject to what US tax lawyers call "dash-six" liability, or liability for unpaid taxes on the consolidated or combined return. Another reason is anyone paying a premium over the current tax basis the project company has in its assets will want the premium to be reflected in a "step up" in the tax basis so that the buyer can recover the premium through additional depreciation.

The value of the step up tends to be higher in renewable energy projects than in other types of businesses because renewable energy assets are subject to faster depreciation allowances. There is usually no additional depreciation for the premium if corporate shares are purchased. This becomes a math exercise. The buyer will pay less because of inability to step up asset basis. The issue is whether the tax savings to the seller are worth the lower purchase price.

It is rare to see direct sales of project assets, because the assets usually include a power contract, interconnection queue position and permits that require consent from other parties to transfer. Most "asset" sales are sales of the project company or an interest in the project company.

Capitalization

Some time should be spent thinking about how to capitalize each US holding company, assuming part of the capital cost of the project will come from overseas rather than raising the entire cost locally.

The way to think about the question is to focus on the overall tax burden on the operating earnings from the project — not just in the United States, but also at the US border when earnings are repatriated and in the home country of the foreign company or investment fund. The US corporate income tax is 21%. There is a 30% withholding tax on dividends when earnings are repatriated. The withholding tax is often reduced under bilateral US tax treaties.

If the foreign investor injects part of its investment in the US holding company as a loan rather than injecting it entirely as equity, then the share of earnings pulled out as interest on the loan will attract a US withholding tax, but the interest may be deductible, reducing the income on which the 21% corporate tax has to be paid. This is called "earnings stripping." Some US tax treaties waive withholding taxes altogether on interest while reducing, but not eliminating, the rate on dividends.

The US adopted three measures at the end of 2017 to tighten its rules on earnings stripping.

Interest can no longer be deducted when paid to a shareholder who owns more than 50% of the US corporation by vote or value unless the payment is treated as interest in the foreign country where the shareholder resides. (For more details, see "Final US tax bill: Effect on project finance market" in the December 2017 *NewsWire*.)

The US also placed a cap on interest deductions. Interest cannot be deducted to the extent it exceeds 30% of adjusted taxable income. (For more details, see "Cap on interest deductions explained in the August 2020 *NewsWire*.)

Finally, the US also imposes a base erosion and anti-abuse tax, called BEAT, whose goal is to ensure that multinational companies do not use cross-border payments to reduce their US taxes to less than 10% of an expanded definition of taxable income. The BEAT rate increases after 2025 to 12.5%. (For more details, see "Final US tax bill: Effect on project finance market" in the December 2017 *NewsWire*.)

The US used to limit how thinly-capitalized a company can be and still deduct interest. The US would not allow part of the interest paid to a foreign parent company to be deducted if the debt-equity ratio of the US holding company exceeds 1.5 to 1 and the foreign parent company is in a country with a favorable US tax treaty that waives or reduces US withholding taxes on interest payments. At worst, part of the interest paid to the foreign parent company each year could not be deducted.

The US dropped any bright-line debt-equity ratio after 2017 in favor of the other tools for combatting earnings stripping. The decision how much of an inbound investment should be made in the form of shareholder debt has become more complicated as a result. (For a more detailed discussion, see "How much shareholder debt?" in the April 2021 *NewsWire*.)

Another challenge when trying to strip earnings is that capital-intensive businesses run losses. There may be no earnings to strip. The typical renewable energy project does not turn tax positive until sometime in the fourth year after the project goes into service. If the developer retains the US tax subsidies, rather than barters them in a tax equity transaction, then it can be as long as nine years before the project turns tax positive. Unused tax subsidies can be carried forward up to 20 years and used to shelter future income from the project from tax. Stripping earnings during a period when the US holding company is in a net loss position has the effect potentially to increase the overall tax burden. It may subject the earnings to a withholding tax earlier in time at the US border or in the foreign country, assuming the earnings are not exempted from taxes in the home country under a participation exemption or similar provision and the foreign country does not already tax them by looking through the US holding company under a controlled foreign corporation regime.

When borrowing from third parties to raise capital for any equity the foreign parent must inject into the project, consider whether the debt should be in a location in the capital structure that allows the interest to be deducted by the foreign parent directly. The US holding company may not have enough tax base to deduct the interest in the US. The foreign parent might borrow directly and inject the funds as equity into the US holding company. This would give the parent an interest deduction at home. There are no earnings to strip in the US. Alternatively, the debt might be put in an entity one tier up from the US holding company that is transparent for tax purposes in the home country of the foreign parent company, and the borrower would then inject the money as equity into the US holding company.

Until recently, it was common to use an intermediate holding company in a jurisdiction with a favorable tax treaty with the United States to invest in US projects. An example might be a Dutch or Luxembourg holding company. If the foreign investor is in a country without such a tax treaty, this was a way to qualify for a reduced withholding tax rate. However, recently-negotiated US treaties have limitation of benefits clauses that make such treaty shopping difficult. The foreign investor must have a meaningful business presence in the intermediate jurisdiction to be able to benefit from the treaty. ◎

Data Center Sustainability: Beyond PPAs

by Marissa Leigh Alcala and Rachel Rosenfeld, in Washington

Data centers are being driven by customers to reduce carbon footprints, consumption of energy, water, raw materials and the amount of waste they produce.

Various metrics are being used to measure progress on these fronts.

Green leases are being used to document commitments.

Documenting Sustainability

Data center customers want transparent and quantifiable measurements of sustainability. Some customers are required to comply with mandatory environmental and infrastructure codes. Others are vying for third-party published awards and rankings, while some have published goals for their organizations on carbon neutrality and other sustainability targets.

Some data center customers remain who value price over sustainability, but a recent survey by 451 Research found that almost a third of multi-tenant data center representatives said all of their customers want contractually binding commitments to efficiency and sustainability, while another 44% said most of their customers want this.

Sustainability commitments are being written into green leases.

A green lease uses standard lease clauses that provide for the management and improvement of the environmental performance of a building to align financial incentives and sustainability goals between a landlord and a tenant. Green lease provisions may incentivize energy and resource efficiency investments, streamline renewable energy procurement and support sustainable building certifications.

Some of the most common efficiency metrics to measure the sustainability and efficiency of a data center include the following: PUE (power usage effectiveness, a metric of energy efficiency), WUE (water usage effectiveness, a measure of how efficiently water is used) and CUE (carbon usage effectiveness, a metric of operational sustainability).

These metrics were developed by the nonprofit industry consortium The Green Grid. The Green Grid is currently developing a new IUE metric (infrastructure utility effectiveness) to determine how much design infrastructure capacity an operational data center is able to use. The goal of this new metric is to identify stranded capacity and opportunities to improve efficiency. These and other metrics may be incorporated into green lease provisions, or used as benchmarks for corporate sustainability goals.

In addition to green lease terms between a data center landlord and tenant, data centers can apply for certification under green building rating systems.

In the United States, the most widely used green building rating system is the Leadership in Energy and Environmental Design (LEED) developed by the US Green Building Council. Data centers may also be certified for energy efficiency under the national data center energy efficiency information program by Energy Star, part of an initiative by the US Environmental Protection Agency and the US Department of Energy. Only data centers in the top 25% in energy performance may receive Energy Star certification. Certifications on energy efficiency and sustainability are also available through government programs in other countries, as well as third-party certification providers. BREEAM certifies sustainability ratings for buildings and other infrastructure projects, both during construction and for in-use facilities, in 89 countries. CEEDA (Certification of Energy Efficiency for Data Centers) is a global organization with certification standards designed specifically for different types of data center facilities.

Top industry players also compete for a number of sustainability awards and rankings. These include accolades from the following organizations: GRESB (the Global ESG Benchmark for Real Assets, a nonprofit that evaluates ESG performance data), the Carbon Disclosure Project (a nonprofit that runs a global disclosure system for investors, companies, cities, states and regions to manage their environmental impacts), RE100 (an initiative of global businesses, aiming for a transition to 100% renewable electricity), Sustainalytics (an independent global provider of ESG and corporate governance research and ratings), the US EPA's green power partnership (a voluntary program that encourages organizations to use green power as a way to reduce the environmental impacts associated with conventional electricity use), REBA (the Renewable Energy Buyers Alliance, a group of energy buyers aiming to achieve a zero-carbon energy future) and the Data Center Coalition's energy committee (the energy committee of the trade association for the data center industry).

Advances in Design

Focus on sustainability in design can start as early as site location.

Electing to build a data center on a brownfield, rather than greenfield, site may be considered to facilitate re-use or re-purposing of existing building infrastructure. Proximity of public transportation may be factored in to cut down on carbon emissions from vehicle traffic.

Increasingly, data center owners and operators are assessing and selecting construction and internal infrastructure materials based on environmental performance and implications such as carbon footprint, hazardous chemicals and recycling or refurbishing opportunities.

Data center design and construction is taking into account "embodied" carbon (carbon emissions resulting from construction supply manufacturing, transportation and installation) as part of the effort to have a more accurate measurement of the data center's true carbon footprint. Building Transparency, a nonprofit, manages the embodied carbon in construction calculator (EC3) — a free tool providing access to supply chain data and measurements on embodied carbon in construction materials. Use of EC3 is being promoted in the data center industry. The EC3 tool allows a user to see the carbon and price impact of electing different choices in building materials.

Technology advances in building materials help make these choices possible.

In one example, CarbonCure, a concrete material, is now used for tile walls that frame data centers. Concrete's durability and strength are ideal for industrial construction, but the production of cement requires the use of substantial energy, and the actual chemical process emits very high levels of CO2. CarbonCure takes CO2 produced by large emitters such as refineries and chemically mineralizes it during the concrete manufacturing process to make greener and stronger concrete. The process reduces the volume of cement required in the mixing of concrete, while also permanently removing CO2 from the atmosphere.

Another greener replacement material is a natural fiber-filled polypropylene, derived from jute fibers, that has been developed for use in parts inside and outside the rack, including adapters, bus-bar covers and other mechanical parts inside the server.

In order to contribute to joint innovations and the common goals of increasing sustainability, maintaining efficiency in production and promoting favorable economics, information on innovative and sustainable materials is shared across the data center industry through forums, including the nonprofit Open Compute Project, an organization that shares designs of data center products and best practices.

In addition to siting, materials fabrication and construction management, data center design is advancing to increase overall sustainability and efficiency.

Modular data center construction prevents over-building upfront and allows incremental capacity to be added as needed over time. This avoids the construction of massive data centers where a single-tenant cloud provider or multi-tenant colocation owner may require years to work up to using the building's capacity. This also has the added benefit of allowing for faster time to market. A modular system facilitates design of components to have their own sustainable lifecycles.

High-density construction leverages the space in a data center more efficiently and packs more computational power into a smaller amount of real estate. Advanced cooling technologies are key in high densities, given the increased heat generated by components packed closely together. Where prior construction required raised floors or room-level air cooling in order to cool servers, new approaches such as cooling through cold plates and tubes and immersion cooling technology eliminate the need for hot air and cool air aisles and major HVAC systems pumping air in and out of the data center. Immersion cooling seals servers and other electronic equipment / continued page 38

Data centers are being driven by customers to reduce carbon footprints and consumption of energy, water and raw materials.

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in a dielectric liquid with a boiling point lower than water. In single-phase immersion cooling, the fluid is cycled out to a heat exchanger where it is cooled and then cycled back to the immersion tank. Two-phase immersion cooling allows the fluid to boil and the resulting vapor to condense on a heat exchanger inside the immersion tank. These advanced cooling technologies reduce both energy and water consumption.

Use of Technology

Sophisticated technologies, such as artificial intelligence and machine learning, are being used in data center design and operation to increase both sustainability and efficiency.

Technology is used in data centers to monitor energy consumption, water use, temperature, humidity and peak demand cycles, and it can serve in various functions, including smart temperature and lighting controls, rainwater reclamation, waste heat recycling and efficient cooling.

Green leases are being used to document commitments.

AI and machine learning technology can identify where equipment is wasting electricity, hot spots inside a data center and anomalies or performance issues in processes or equipment. This information can be used to minimize downtime and increase output, and it can train deep neural networks to optimize data center performance and increase efficiency. Prognostic artificial intelligence can forecast future events such as surges in demand or temperature changes and adapt system variables accordingly. Use of prognostic AI can prevent a data center from going beyond its operating constraints while also ensuring it operates as efficiently as possible.

Google has used machine learning in its data centers to control cooling systems, as developed by its artificial intelligence research group, DeepMind. Every five minutes, the cloud-based AI pulls a snapshot of the data center cooling system from thousands of sensors and feeds it into deep neural networks to predict how different combinations of potential actions will affect future energy consumption. The AI system then identifies which actions will minimize energy consumption while satisfying a set of safety constraints. Those actions are sent back to the data center, where the actions are verified by the local control system and implemented. Use of this AI resulted in a 40% drop in energy used for cooling and a 15% reduction in overall energy consumption.

The use of artificial intelligence not only increases the density of data center components by packing more computing power into each piece of equipment, but it also allows for more tailored cooling solutions to combat any rise in heat resulting from increased density.

Many technology majors have developed their own bespoke systems suited to their data centers. Huawei created several AI-based systems, including iCooling, iPower and iManager, that allow for intelligent thermal management, an increase in data center availability and a reduction in inefficiencies. Equinix developed IBX SmartView, a bespoke data center infrastructure management software-as-a-service tool to analyze the operations of its data centers.

Some of the largest industry players are also undertaking research and testing in pioneering technologies as they work toward lowering the carbon output of data centers. Microsoft is currently working on initiatives that include underwater data centers for edge computing scenarios with controlled environments that may also extend the life of servers, data storage using DNA and holograms to house immense amounts of data, and containerized data modules that use satellite broadband connectivity, allowing capacity to be deployed in geographies with no fiber infrastructure.

Water Conservation

Sustainable water strategies for data centers include both sourcing and design.

Water is primarily used in data centers for cooling. About 40% of the power consumed by a data center may go toward air-conditioning. Use of water-based evaporative cooling technologies has been a common tool to reduce power consumption. This reduction in power consumption comes at the expense of increased water usage. Data center operators are stepping up their efforts to reduce reliance on water supplies, as global sustainability movements increase the focus on water as a finite resource.

On the water supply front, a data center district may include water treatment plants that allow the data centers to cool their servers using local bodies of water or wastewater from municipal water systems or shared cooling solutions, such as district chilled water and river water cooling loops. Google has data center districts in Virginia, Washington and Texas that offer "grey water" feeds providing recycled wastewater to industrial customers. Availability of water supply alternatives may also factor into data center siting.

On the design front, an increasing number of data center providers are choosing cooling systems with minimal or no need for water. Where temperatures are low enough, fresh-air cooling can be employed. In hotter climates, innovative coolant solutions, refrigerant economization, water-to-the-chip technology, immersion cooling and rear-door chilling units provide effective cooling without high water consumption. Data centers that continue to use water for cooling are incorporating rainwater recovery strategies that capture rain from huge roofs or parking lots and store it on site, reducing potential burden on local water systems.

Facebook has deployed the StatePoint liquid cooling system, a new evaporative cooling system using a liquid-to-air energy exchanger where water is cooled as it evaporates through a membrane separation layer. The StatePoint liquid cooling requires less water than a typical indirect cooling system by using air to cool water instead of using water to cool air. Based on testing for several different locations, it is anticipated that StatePoint liquid cooling can reduce water usage by more than 20% for data centers in hot and humid climates and by almost 90% in cooler climates, in comparison with previous indirect cooling system technologies.

The Green Grid nonprofit industry consortium is currently developing a total-cost-of-ownership calculator for liquid cooling data centers to forecast the benefits of incorporating liquid cooling in a data center environment. This tool is planned to be flexible enough to integrate different liquid cooling technologies in variable IT environments and will provide an assessment of cost.

Facebook and other data center majors also invest in circular systems that reuse water as many times as possible before releasing it to wastewater treatment plants. Amazon and others are treating water themselves as they re-use it in their data centers. Data center majors have also taken on water restoration projects in water-stressed regions to promote long-term sustainability of the local watersheds. Recently, Microsoft announced that it will be "water positive" in all of its direct operations by 2030, meaning that the company will reduce the volume of water it uses and replenish more than it consumes.

Water consumption is on its way to becoming as visible a sustainability factor for data centers as energy consumption. Many actors in the data center industry are tracking their water use and reporting it in their performance and sustainability metrics. Some, such as Amazon, have developed their own water efficiency metrics. Others, such as Digital Realty Trust, a real estate investment trust that invests in carrier-neutral data centers and provides colocation services, analyze and track their water-scarcity risks using the World Resource Institute's AqueductTM tool to inform data design decisions and water conservation project selection.

Reducing Waste

Data center owners, operators and customers also consider waste materials and waste heat in evaluating sustainability and efficiency.

The ability to document a net-zero waste-stream impact has the potential to emerge as a meaningful metric for data center service providers, as customers consider the entirety of their data center's sustainability programs.

Data center owners and operators consider the lifecycle and carbon footprint of materials and components in how hardware is designed, operated and decommissioned and aim to re-use, recycle and generally divert materials and waste from landfills. This requires an understanding of the daily inflow of materials and outbound flow of goods and services compared with the subsequent outflow of material that is reclaimed, repurposed, recycled or disposed of as waste.

In order to address the sustainability of data centers comprehensively, data center designers also look to minimize the amount of toxic-laden electronics that end up in landfills and to generally eliminate the use of hazard- */ continued page 40*

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ous, scarce or difficult-to-create materials altogether.

A key priority is tracking the environmental impact of construction components, including the carbon footprint of the manufacturing of materials and a "reverse-logistics" process to track the waste stream and disposition of debris. Data center owners and operators have found opportunities to reuse hardware within their own data centers. When equipment reaches its end of life at that data center, data center owner-operators engage third parties who remarket components to find a second useful life. Some data center equipment suppliers specifically focus on refurbishing existing parts in an effort to promote waste reduction. When remarketing or refurbishing is not an option, recycling partners break down equipment for reclamation and recycling.

Managing packaging for equipment that is shipped to a data center is also an important facet of comprehensive waste stream accountability.

Waste heat from data centers can be recycled on-site and used in energy production, and waste heat not recycled on-site can be used by neighboring businesses or homes for heating. Data centers are increasingly becoming heat providers. Amazon's corporate headquarters in Seattle has been kept warm by using waste heat from a non-Amazon 34-story data center in a neighboring district. Various northern European countries are directing data center waste heat into district energy systems for reuse. Stockholm's Data Parks hope to use waste heat from data centers to heat 10% of the city by 2035. Facebook is directing waste heat from its data center operations in Denmark to heat nearby homes in Odense. Notre Dame University is using waste heat from a data center to heat a campus greenhouse. Syracuse University's data center transfers excess cold and hot water for air conditioning and heating to a nearby building. While the United States is not on par with Europe, California will be mandating waste heat recovery for data centers in its building efficiency standards. ◎

Environmental Update

The US Environmental Protection Agency said on May 27 that it plans to revise a Trump-era rule that limits the ability of state and tribal governments to review the water quality impacts from projects seeking federal permits under the federal Clean Water Act.

A federal agency may not issue a permit or license allowing any activity that may lead to discharges in "waters of the United States," unless a section 401 water quality certification is issued or the need for certification is waived. The Clean Water Act generally makes state and tribal governments where the discharge would occur responsible for issuing certifications to ensure that local water quality is protected.

EPA directed in June 2020 that state and tribal governments should certify or reject projects within one year. It limited state and tribal discretion to certify or reject water quality impacts, and it prohibited other considerations such as climate change impacts.

The Trump administration argued that curbs to local authority were necessary because too many states had been using clean water laws to block fossil-fuel projects such as pipelines and coal terminals from getting the necessary permits. It said that limiting local discretion would advance principles of "cooperative federalism" because the restrictions better balance the agency's regulatory powers with those of the states and tribes.

Critics said local authority should remain where a discharge would contravene state water quality requirements.

EPA has not said yet exactly what changes it plans. However, it will not return to the 1971 regulations that were in effect before Trump scaled back local authority.

While the Biden administration said it wants to strengthen the authority of states and tribes to protect their own water, it is simultaneously pushing broad-ranging infrastructure development that will also require state and tribal water quality certifications.

EPA published a notice of intention to revise the rules in this area in the Federal Register on June 2. The agency will accept written comments until August 2 on a series of questions listed in the notice, including the scope of permitted state and tribal government review.

The Trump-era rule remains the subject of consolidated litigation brought by 20 states, the District of Columbia and various tribes and environmental groups in three federal courts. The states complain that the rule upends 50 years of true cooperative federalism.

The states suing to challenge the Trump-era rule include California, Colorado, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New Jersey, New Mexico, New York, North Carolina, Oregon, Rhode Island, Vermont, Virginia and Wisconsin.

Seven Republican-led states have intervened in defense of the Trump rule, namely Louisiana, Montana, Arkansas, Mississippi, Missouri, Texas, West Virginia and Wyoming.

EPA asked the courts on June 4 to delay the litigation to allow time for the litigants to determine how the agency's announcement of a replacement rule may affect the lawsuits.

Regulated Waters

EPA Administrator Michael Regan said on June 9 that EPA will revoke a 2020 Trump rule that significantly narrowed the types of navigable waters that the federal government views as protected under the Clean Water Act as "waters of the United States." The 2020 rule stopped federal oversight of water pollution in many tributaries of larger waterways and much of the arid West.

EPA will begin crafting a new, more expansive definition of which waterways are subject to federal water protections, but it appears the agency will leave the current definition of what constitutes a "waters of the United States" — and is therefore subject to regulation — in place until the rulemaking process is complete.

Regan said that the Trump rule is already leading to "significant environmental degradation" by allowing more than 300 projects that would have previously required Clean Water Act dredge-and-fill permits to proceed without such oversight.

Where a replacement rule will land in terms of the scope of regulated waters remains uncertain. Regan said he is committed to a new, more protective definition that is "durable," consistent with Supreme Court precedent, and informed by the last two decades of debate as to the act's scope.

The issue is particularly sensitive to farmers who were fiercely opposed when the Obama administration wrote a broad definition of protected waterways in 2015. Regan heard from North Carolina farmers and ranchers when he headed the North Carolina Department of Environmental Quality, many of whom supported his appointment to lead EPA.

EPA and the US Army Corps of Engineers asked a US district court hearing one of a dozen lawsuits challenging the Trump-era rule to send the rule back to the agency so that it can rework the definition. However, EPA and the Corps did not ask the court to vacate the rule in the meantime, meaning they probably intend to leave it in place until the new rulemaking process has been completed. The district court case is *Conservation Law Foundation v. EPA*.

Environmental groups are not happy.

The new rulemaking process could take a year or more. Any decisions that the Army Corps makes about what is considered a regulated waterway in the meantime would normally be expected to remain good for five years.

Phase I Site Assessments

The current industry standard for conducting most phase I environmental site assessments of industrial and commercial properties is expected to be replaced with an updated version later this year.

The purposes and current limitations of such assessments are not always well understood.

Phase I site assessments are almost always required before closing financings, commercial or industrial real estate purchases, or mergers and acquisitions.

A qualified environmental professional is employed to assess potential environmental risks by physically inspecting sites and observing adjacent properties, interviewing knowledgeable parties, and reviewing certain historical information and government regulatory databases that may yield information relevant to site conditions. Although a phase I site assessment requires an inspection of a property, no invasive sampling is typically performed. The inspector looks for visual evidence of environmental contamination or risk of such contamination.

The goal is to identify and disclose recognized environmental conditions, or "RECs."

The current 2013 standard defines a recognized environmental condition as "the presence or likely presence of any hazardous substances or petroleum products in, on, or at a property: (1) due to any release to the environment; (2) under conditions indicative of a release to the environment; or (3) under conditions that pose a material threat of a future release to the environment." The term "hazardous substances" is defined as substances that are regulated under the federal Superfund law also known as CERLCA.

Minor conditions, referred to as */ continued page 42*

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"de minimis," are not treated as RECs. A condition is minor if it "generally does not present a threat to human health or the environment and . . . generally would not be the subject of an enforcement action if brought to the attention of appropriate governmental agencies."

Anyone doing due diligence should be aware that phase I site assessments may not cover everything potentially of interest to a buyer or financier.

There are three key limitations to keep in mind, particularly by buyers and financiers who did not engage the consultant directly. First, consultants are not required to recommend areas where additional investigation would be sensible, even if indicated by the facts. Second, assessment is not required of various types of environmental risks that are considered "non-scope." Third, the consultant doing the site assessment is required to consider only hazardous substances that are already defined as such under the Superfund law or that are considered "petroleum products." Not included are substances that are only regulated under state or other federal environmental laws and substances that are under consideration for regulation under Superfund but the regulation of which is not yet final.

While the scope of hazardous substances regulated under Superfund overlaps broadly with most other environmental laws, the overlap is not 100%.

The "hot topic" of concern related to this limitation is the emerging contaminants class known as per- and polyfluoroalkyl substances, or PFAS (pronounced "PeeFAS"). Also referred to as "forever chemicals" due to their durability and reported persistence in the environment, PFAS are a broad group of fluorinated chemicals that have been widely used in the United States and around the globe since the 1940s. This class of chemicals is under increasing regulatory scrutiny at both the federal and state levels, with many states already taking steps to regulate in advance of federal action and federal regulation under active consideration in Congress.

Despite that scrutiny, under the current standard for phase I site assessments, PFAS are considered non-scope substances falling outside of the CERCLA regulatory sphere. EPA clarified that the current standard generally does not require analysis of PFAS in an advance notice of proposed rulemaking on January 14, 2021 soliciting public comment and data to inform its ongoing evaluation of PFAS. "PFAS [are] not . . . CERCLA nor RCRA listed hazardous substance[s]."

Many consultants flag in their phase I assessments the possibility that there may be PFAS on the site, but a buyer or financier cannot count on the consultant to do this in cases where it is merely a relying party who did not actively engage the consultant to do the assessment.

PFAS have been used for decades in hundreds of industrial applications and consumer products. The following types of historical activities suggest possible PFAS: carpets and textiles, airport and other firefighting using certain foams, leather tanning and leather production, metal plating, cosmetics, furniture, food paper products and cosmetics. This is not an exhaustive list.

The current EPA standard for phase I assessments includes the following warning for users of these reports: "Users are cautioned that federal, state, and local laws may impose environmental assessment obligations that are beyond the scope of this practice. Users should also be aware that there are likely to be other legal obligations with regard to hazardous substances or petroleum products discovered on the property that are not addressed in this practice and that may pose risks of civil and/or criminal sanctions for non-compliance."

Anyone buying or financing a project where a phase I site assessment will be produced should be sure to review the scope of services specified in the report itself or in the engagement letter with the consultant and, unless stated otherwise, should assume that non-scope items are excluded when doing due diligence.

ASTM Update

The international standards organization American Society for Testing and Materials, or "ASTM," provides widely used standards for "good commercial and customary practice in the United States for conducting environmental site assessments of a parcel of commercial real estate with respect to the range of contaminants within the scope of" the Superfund law and petroleum products.

Changes to the Superfund law in 2002 required EPA to establish standards and practices for making "all appropriate inquiries" when evaluating a property's environmental condition. It is important to follow the EPA regulations not only to assess risk properly, but also to preserve the ability to claim a defense to CERCLA liability as an innocent landowner, contiguous property owner or bona fide prospective purchaser.

The EPA regulations said anyone following two ASTM standards will be considered to have made all appropriate inquiries. The two standards are ASTM E1527 ("Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process") and ASTM E2247 ("Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process for Forestland or Rural Property"). Each of these detailed standards is around 50 pages.

ASTM is expected to replace the current E1527-13 standard with a new ASTM E1527-21 standard later this year as part of its periodic review process. Reconsideration of this standard has been underway since 2018. Once ASTM acts, then EPA will have to confirm that any revised ASTM standards will still satisfy the requirement to have made "all appropriate inquiries."

ASTM seems focused on clarifying the existing language and making the phase I reports more comprehensive.

ASTM is expected to clarify what the definition of recognized environmental condition means when it uses the phrase "likely presence" of hazardous substances is expected.

The current standard defines a recognized environmental condition as "the presence or likely presence of any hazardous substances or petroleum products in, on, or at a property." There has been some debate over when a consultant should opine that such substances are "likely" present in the absence of positive proof.

Another change reportedly under consideration would define "likely" in that context as "that which is neither certain nor proved, but can be reasonably expected or believed by a reasonable observer based on the logic and/or experience of the environmental professional, and/or available evidence, as stated in the report to support the opinions given therein."

ASTM may decide that consultants should use a "reasonable observer" standard informed by the facts and more strictly tied to assumed expertise and judgment.

Other changes under consideration are to require the consultant to provide a more complete explanation why particular site conditions do not rise to the level of a recognized environmental condition in cases where releases described in the report are either historical or controlled. This would set a bar for what has to be disclosed when determining that a past release should not be considered a recognized environmental condition.

The current standard defines an historical recognized environmental condition as "a past release of any hazardous substances or petroleum products that has occurred in connection with the property and has been addressed to the satisfaction of the applicable regulatory authority or meeting unrestricted use criteria established by a regulatory authority, without subjecting the property to any required controls (for example, property use restrictions, activity and use limitations, institutional controls, or engineering controls)."

The new standard may require the consultant to review "reasonably ascertainable" information to confirm that a regulatory authority has cleared the property for unrestricted use or why it otherwise qualifies.

It may also require the consultant to consider whether there have been any changes in applicable regulatory cleanup criteria or migration pathways that would turn an historical condition back into a current condition.

The current standard defines a controlled recognized environmental condition as "a recognized environmental condition resulting from a past release of hazardous substances or petroleum products that has been addressed to the satisfaction of the applicable regulatory authority (for example, as evidenced by the issuance of a no further action letter or equivalent, or meeting risk-based criteria established by regulatory authority), with hazardous substances or petroleum products allowed to remain in place subject to the implementation of required controls (for example, property use restrictions, activity and use limitations, institutional controls, or engineering controls)."

The new standard may require the consultant to explain why a condition should be considered controlled rather than a current condition requiring attention and provide supporting information.

Another revision may finally make crystal clear when a phase I site assessment is too stale. The revision should clarify that the date on the report cover is irrelevant for that purpose. Instead, each specific diligence inquiry required by the standard — including the site visit, interviews, search for environmental cleanup liens and government records searches — must have been done within 180 days before closing the transaction.

The market is watching for whether the ASTM will require disclosure of emerging contaminants like PFAS. It is possible that the new version will simply add emerging contaminants like PFAS, along with such things as asbestos and wetlands, to the list of "non-scope" issues that do */ continued page 44*

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not have to be disclosed. Even if ASTM were to require disclosure in the body of the report, this would probably not lead to increased awareness unless the issue is flagged in the conclusions section where the eyes of many users land and rarely stray.

Offshore Wind

The "record of decision" that the Bureau of Ocean Energy Management issued in May allowing the 800-megawatt Vineyard Wind project off Massachusetts to move forward is like the starting gun at the start of a large race. The Biden administration hopes to see another 36 offshore wind projects of similar size built by the end of the decade.

Vineyard Wind plans 62 turbines about 15 miles off the coast of Martha's Vineyard in Massachusetts. The project is expected to be in service as early as 2023.

The administration hopes that its target of 30,000 megawatts of offshore wind by 2030 will draw $12 billion in capital investments per year and support 77,000 direct and indirect jobs by 2030.

Three are more than 5,000 offshore wind turbines operating currently in Europe compared to just seven in the United States. The Biden goal translates to 2,000 US turbines by 2030.

Offshore wind projects are currently planned off the US east coast from Maine to North Carolina. Biden is also taking steps to open the Gulf of Mexico and an area off California to offshore wind development.

Permits for projects off the east coast are expected to be put on a fast track. The US Department of Energy is expected to offer $3 billion in federal loan guarantees for offshore wind projects. US ports will also have to be upgraded to support offshore construction.

West coast development is farther behind the east coast and will involve floating turbines because water depths will prevent bolting turbines off the Pacific coast to the ocean floor.

Twelve miles and beyond is the sweet spot for limiting onshore visual impairment from offshore wind farms. Depths at that distance from shore in the east can be 100 feet or less in some areas compared to five times that depth or more out west.

Two pilot-scale wind power projects are currently being proposed off California.

The US Department of Defense has promised to be more flexible in accommodating offshore wind projects in areas near where it conducts testing and training operations, but the practical and regulatory challenges for west coast production are comparatively daunting. Unlike many eastern states, California has yet to commit to purchases of offshore wind energy as part of its renewables strategy.

— contributed by Andrew Skroback in New York