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Beneath the Surface: The Emerging US Consensus on Climate Change

A conservative Republican former congressman, an associate editor of the conservative *National Review*, a former policy analyst for the National Association of Manufacturers and the head of the leading renewable energy trade group in Great Britain had a spirited debate this spring on climate change at an event in Phoenix hosted by Avangrid Renewables. The following is an edited transcript.

The panelists are Greg Bertelsen, senior vice president of the Climate Change Council and a former energy and environmental analyst for the National Association of Manufacturers, Bob Inglis, a former six-term Republican congressman from South Carolina and now head of republicEn.org, Travis Kavulla with the R Street Institute, a Washington think tank, an associate editor of the *National Review* and a former deputy chairman of the Montana Public Utility Commission, and Emma Pinchbeck, executive director of RenewableUK. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Public Opinion

MR. MARTIN: Greg Bertelsen, you are optimistic that the United States government will address climate change, despite the fact that as recently as 2017, only 7% of Republicans believed we need to do something about it and despite the steady / *continued page 2*

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OFFSHORE WIND projects more than 12 miles offshore are less likely to be subject to state laws after a US Supreme Court decision in mid-June.

Brian Newton worked for Parker Drilling on oil rigs on the outer continental shelf off the California coast. He worked 14-day stretches at a time, with 12 hours each day on duty and 12 hours on "standby." California minimum-wage and overtime laws would have required Parker to compensate him for the time he spent on standby. The federal "Fair Labor Standards Act" does not.

Newton filed a class action suit against Parker seeking compensation. The parties agreed that federal law applies on the / *continued page 3*

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questioning of the basic science by the Trump administration and Fox News. Why?

MR. BERTELSEN: I look at the underlying fundamentals that ultimately drive US policy action.

Start with an organization like ours, which is made up of large energy companies, like ExxonMobil, Total and BP, the largest utility in the country, Exelon, a large Spanish bank, Santander, leading consumer-brand companies, like Proctor & Gamble and Johnson & Johnson, and large environmental organizations, like the Nature Conservancy and WWF — what used to be known as the World Wildlife Fund — all working together to formulate a policy that both Republicans and Democrats can get behind. That coalition continues to grow month by month. Its goal is to put a price on carbon.

Climate change is a slow-moving Sputnik moment.

MR. MARTIN: So there is growing support from the business community for action on climate change.

MR. BERTELSEN: Absolutely. We have never seen this level of support among the corporate community for action on climate change, and that will only increase.

MR. MARTIN: Let me challenge you. You left the National Association of Manufacturers to join this group. The NAM has 14,000 members, and they could not come to a consensus. Are things any better today at the NAM?

MR. BERTELSEN: Without question, yes. First, 14,000 companies across the country are never going to come to a consensus position on climate policy. It is not going to happen. But the scales are tipping every day more toward action rather than inaction.

For the last three Congresses before the current one, Steve Scalise, the House Republican whip, introduced a resolution that it is the sense of Congress that a carbon tax should not be adopted. Every Republican until the last Congress voted for it. The National Association of Manufacturers the first two times sent a letter to all members of Congress encouraging members to vote for the resolution on grounds that it is a critical manufacturing issue. In the last Congress, the NAM was notably silent. It is a minor data point, but you can see a big organization like that starting to turn. The NAM no longer opposes a carbon tax. It has moved to neutral.

MR. MARTIN: Bob Inglis, you were a conservative Republican member of the House. Do you see the same shift among Republicans on climate change?

MR. INGLIS: Yes. I think that things are turning dramatically. Probably the best evidence is the headline in a press release from the Energy and Commerce Committee Republicans on February 6. “Republicans are focused on pragmatic solutions to climate change.” The next day, three senior members of that committee on the Republican side followed up with an op-ed piece whose lead sentence read: “Climate change is real and we, the leaders on the Republican side of the Energy and Commerce Committee, are here to do something about it.”

MR. MARTIN: So we are starting to see a shift among Republican members of Congress in the last year?

MR. INGLIS: Since the November elections, actually. [Laughter.] November was quite a wake-up call.

Green New Deal

MR. MARTIN: The Democrats seem to be veering to the left. They have a “Green New Deal.” They hope to make climate change a key issue in the 2020 election. It is too early, of course, to know what the key issues will be, but do you think climate change will be a winning issue for the Democrats?

MR. INGLIS: I think not. I think it will split the Democratic party. The Democrats are getting ready to have a tea party led by Alexandria Ocasio-Cortez. I don't think Nancy Pelosi was tongue-tied when she said, "The green dream, or whatever they call it." I think that was actually intentional on Nancy's part to say, "Hush up. Frank Pallone, the Energy and Commerce Committee chairman, is going to handle this. His committee is where the action should be. Not with you, AOC." I think that is what Nancy was doing, and Nancy is a pretty shrewd politician. She knows that she has to keep the Democrats from forming a tea party that ends up with something that further polarizes America.

MR. MARTIN: Travis Kavulla, why is the Green New Deal polarizing?

MR. KAVULLA: I think it is intended to be polarizing. The intention is to lay down a marker of swift radical transition. It has been characterized by its sponsors as a kind of national mobilization and interestingly, the fire coming from the Green New Deal is not trained on Republicans. It is trained on Democrats who are labeled insufficiently pro-action. We saw this in that cringy video of Green New Deal activists confronting Senator Diane Feinstein. The Green New Deal is becoming a source of division within the Democratic party.

Words like the "Green New Deal" conjure up government-led industrial policy as opposed to liberalization. Ironically, if you look at the electric power sector, it has been transformed by a series of liberalizing policies like direct consumer access and restructured competitive markets that have actually led to decarbonization.

At least to people who know the electric power sector, the Green New Deal seems awkward in the sense that it purports to be a kind of government hand, which is exactly the thing that led to many of the inefficiencies and a lot of the carbon intensity that the liberalizing policies have been helping to undo.

MS. PINCHBECK: The Labour party in the UK has now adopted the Green New Deal idea because they are desperate to win back the young voters they have lost.

My first reaction after reading the Green New Deal was it is fundamentally undeliverable. A lot of energy analysts did the same smug thing for about 48 hours. It is just a bucket list of things that are impractical. Why is all this social stuff in it, too, when it is supposed to be an energy policy.

However, on reflection, no policy is perfect. The ambition is in line with the science. We can dislike how radical the action is and dislike the type of action that is / *continued page 4*

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outer continental shelf, but they disagreed over how to interpret a phrase in the federal "Outer Continental Shelf Lands Act" that treats the law of the adjacent state as the governing law to the extent the state law is "applicable and not inconsistent with" federal law.

The court said the federal Fair Labor Standards Act is a comprehensive statute governing overtime and minimum-wage issues and leaves no gap for the state to fill. Under this standard, state laws would only apply when they deal with subjects that federal law has not already addressed.

The case is *Parker Drilling Management Services, Ltd. v. Newton*.

Between 1793 and 1988, the United States treated its territory as extending three miles out to sea. President Reagan issued a proclamation in 1988 extending the US territorial sea to 12 miles after 104 other countries had already extended their own boundaries this distance in a United Nations law-of-the-sea treaty. Both the US and British navies had been resisting the extension, as both wanted free passage closer to shore for naval vessels.

There has been tension for decades between the federal government and the states over who has control of the waters out to the three-mile — and more recently 12-mile — limit.

The tension has been largely over control of mineral rights rather than how other laws are applied.

For example, the US government sued in the 1940s to block California from continuing to lease private parties the rights to remove oil, gas and other mineral deposits within three miles offshore. The US Supreme Court granted an injunction on grounds that the federal government has "paramount rights and power over" the territorial sea. Texas and Louisiana continued carrying out activities in the territorial sea, and the United States also secured injunctions against them.

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recommended, but the speed is bang on in line with what science suggests we will need to do. If it creates an urgency in policy and forces everyone to come together on the details, then that is a good thing.

MR. MARTIN: Let me go back to the two Republicans on our panel. Set aside the Green New Deal. Does either of you think that climate change is a winning issue for the Democrats?

MR. KAVULLA: Yes, I do. Democrats have managed to capture the issue from a previous, if not bipartisan, consensus in an era when polling suggested it ranked about level with both parties. Now you see Iowa Democrats listing it as their number two issue going into the coming election season, and you do not see it ranked anywhere among the top concerns of Republicans.

It should concern everyone that it has become a politicized issue. I think Bob Inglis is correct that you hear a new message coming from the Republican political leadership. It remains to be seen whether the kind of pleasing bromides that emerge in press releases will translate into any kind of meaningful policy endorsements, but the business community has opened the door. One of the positive externalities of the Green New Deal is that by pulling the Democratic party so far to the left on these issues, it creates space where Republicans can advocate for free market-based policies that have been successful in the US at decarbonizing parts of the power sector.

MR. MARTIN: Bob Inglis, if you were running again for your old seat in Greenville-Spartanburg, would climate change get any traction with that constituency?

MR. INGLIS: Not yet. Not in the reddest district of the reddest state of the nation. Anybody from Idaho here? I might want to pull that punch if there is anyone from Idaho or Texas. Maybe this is not the reddest, but we are pretty red.

Support for action on climate change is still a ways away in those kind of districts, but not in the suburban districts that Republicans must win in order to win back a majority in the House.

MR. MARTIN: Explain Florida, which is on the front line of climate change — rising sea levels are expected to leave a third of the state underwater by the end of the century — and yet the Republican leaders in that state not only are not for action, but they have also scraped references to climate change from the websites of state government agencies. How do you explain that?

MR. INGLIS: That's changing, too. Governor DeSantis is signaling some things about environmental protection that do not go to climate change, but they get mighty close.

The challenge we face in American politics today is to survive as a Republican, you have to slam yourself up on the right-hand wall and see that there is no daylight between you and the wall in your rhetoric. If you are a Democrat, you want to be on the left-hand wall.

Jerry Nadler, who is now chairman of House Judiciary Committee, once told me, "It is exhausting to represent my district." He represents one of the most liberal districts in the country. "I have to wake up every morning trying to out-liberal my district." It is exhausting. The safest place for Jerry to be is slammed on that wall with no daylight between him and the wall, because you let daylight in, you will get somebody on talk radio who runs against you.

Florida Governor Rick DeSantis is trying to figure out a way to speak about climate change without creating too much daylight between himself and the wall. Our goal at RepublicEN.org is to speak in high-octane conservative terms about climate to create a safe space next to the wall. We had an event at the University of Chicago titled, "What Would Milton Friedman Do About Climate Change?" He would internalize the negative externalities. You speak in that language. You keep the daylight from coming between DeSantis and his right.

Utility regulators must decide whether the cost of rare events like wildfires and hurricanes should be socialized and passed through to ratepayers or borne by shareholders and creditors.

Shifting Politics

MR. MARTIN: Let's move to another topic, which is, if there is a fault line in this panel, it should be over the role of government in addressing climate change.

Greg Bertelsen, you were so taken with a proposed carbon tax that George Schultz, Jim Baker and other Republican luminaries pitched to the Trump administration barely two weeks after Trump took office that you left the National Association of Manufacturers and joined the Climate Leadership Council to promote such a tax. Why is it appropriate for the government to lead the charge on this?

MR. BERTELSEN: Thank you for pointing out that I have a history of bad career moves. [Laughter] I joined the National Association of Manufacturers in the second term of the Obama administration essentially to oppose regulations and then two weeks into the Trump administration, I jumped ship to join a carbon tax organization.

It is an interesting way to frame the question. It also informs my answer, which is I happen to believe that climate is both the biggest environmental threat facing mankind and also the greatest economic threat. There never has been a clearer policy solution to that type of challenge than a direct price on carbon as the primary mechanism for both lowering emissions and stimulating economic growth.

MR. MARTIN: Do you think a carbon tax is the only effective way to get there?

MR. BERTELSEN: It is the most effective way to get there. It is also the most surefire way to give certainty to the marketplace, to allow innovators the certainty they need to make the investments necessary to drive lower carbon decisions. In January, the largest group of economists ever assembled on a single statement essentially endorsed the four pillars of the council's policy, a direct price on carbon being the primary one. The leading economists across the country — Republicans, Democrats, young, old — are in agreement that a price on carbon is the best way to go about this.

MR. MARTIN: Do you favor other government actions as well? Subsidies for renewables, for example? Cap and trade?

MR. BERTELSEN: There is absolutely space for complementary policies, but if the objective is rapid decarbonization of the economy, do it in an economically beneficial way. Do it in a way that allows all sectors of the economy to realize potential opportunities for emissions reductions. The starting place for any comprehensive climate policy should be a direct price on carbon.

MR. MARTIN: Travis Kavulla, you told the Senate Energy Committee in February that the states are being ham fisted in how they are trying to deal with climate change. Some states, for example, have renewable portfolio standards to encourage renewables, but at the same time, they

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Having lost the legal battle, the states turned to the political arena. President Eisenhower made it a campaign issue, and worked with Congress after the election on passage of the "Submerged Lands Act" in 1953 giving the states ownership over the submerged lands in the territorial sea. The Submerged Lands Act gave states control over the submerged lands for the first three miles into the Atlantic and Pacific Oceans and to the international boundary with Canada in the Great Lakes, and it gave the states along the Gulf of Mexico the opportunity to prove claims as far out as nine miles. In 1960, the Supreme Court approved the claims of Texas and Florida to nine miles in the Gulf, but denied the claims of Louisiana, Mississippi and Alabama. Texas had entered the Union with a nine-mile boundary while Florida had been readmitted to the Union by Congress after the Civil War with a constitution specifying a nine-mile maritime boundary in the Gulf of Mexico.

As a companion measure, Congress also adopted the "Outer Continental Shelf Lands Act" in 1953 establishing federal jurisdiction over the continental shelf beyond the territorial sea.

The outer continental shelf is treated like a federal enclave within the adjacent state. The US government enforces the law, but applies the civil and criminal laws of the adjacent state. The state tax laws do not apply. The latest Supreme Court decision establishes a standard for determining what other state laws apply.

TAX EXTENDERS are starting to move through Congress.

After several false starts since last fall, the House tax-writing committee was expected as the *NewsWire* went to press to vote out a bill in mid-June that would extend a collection of lapsed tax benefits retroactively from when they expired. Most of the benefits expired at the end of 2017. Most would be extended through the end of 2020.

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give subsidies through zero emissions credits to keep nuclear power plants operating. We end up with more electricity than we need and at an increased cost. Do you think there is any role for federal or state governments to play?

MR. KAVULLA: A lot of the action is in the states at the moment, rather than the federal government, as we do not have a system like the UK where energy policy is made nationally in any meaningful way. Instead, policy is vulcanized on the part of states or even on the part of individual utilities subject to public utility commission regulation.

If you were going to rank the efficiency of policies that can reduce carbon, you would begin with a carbon tax. The second most efficient would probably be cap-and-trade. A third would be some sort of technology-neutral subsidy for technologies that are carbon free, but the last policy gets into a sphere of something like 17th best in terms of efficiency.

There has been a subtle change since November in the message from Republican political leaders in Congress.

When you look at certain state policies — I will pick on Illinois in particular because your question leads me there — which literally subsidize renewable entry and then subsidize other plants to hang around that are threatened by renewable entry, that is bananas.

It is easy to put this in the context of a false dichotomy of do you or do you not favor government action? The reality is we are living in a sphere where government is already heavily involved and where people are paying a carbon tax, but it simply happens to be hidden and inefficient. I am a new ratepayer in the District of Columbia. The district directs a percentage of its renewable energy target specifically at solar. If you take the cost of that set-aside program and divide it by the tons of carbon that are abated as a result, the PJM independent market monitor estimates a carbon reduction cost of $861 per ton.

MR. MARTIN: So we pay extra for poorly designed state programs.

MR. KAVULLA: That is what I am paying on my electricity bills and it is not a line item and it is not a tax, so it does not have that level of transparency. We see state-level activities all over the United States that adopt hidden carbon taxes that are wildly inefficient in trying to achieve their goals.

MS. PINCHBECK: It goes further than that. You are spot on. I am so bored of pointless ideological arguments that do not get anyone anywhere of "should government intervene versus should the market do it?" It is such a reductive way of thinking about the challenge when most of us work in regulated markets of one kind or other.

Climate change calls for a mix of incentives. You mentioned the UK. The UK has a carbon floor price as well as a cap-and-trade regime with the European Union to tackle the energy-intensive bits of the economy. We chose to do a carbon price for that, but the government also introduced research and development funding for some of the technologies that the market would never invest in because they are never going to be something that is particularly valuable commercially. Yet they are very valuable for climate change action.

I think a carbon price would make a massive difference in the US, but when it gets down to telling people how efficient they have to make their homes, I suspect we have to regulate original construction because there is no way to make my mom happy about someone coming in and messing with her house. Of necessity, we end up with a mix of policies.

You are absolutely right that we have no transparency about where costs and benefits stick in the system, and so we have this conversation as if the playing field is level to start, which it is not. For example, the UK Treasury does not take into account climate externalities when doing impact assessments. Hurricane Katrina cost the US economy $11.6 billion. None of that cost from climate change is ever factored into "how much do renewables cost?" or "how much does this green policy cost?" GDP assessments do not cover it, nor do we think about what are the risks to economic growth in a world of scarce resources. Carbon pricing addresses some of that, but not all of it. It is a much more complicated picture than whether to intervene or not.

MR. MARTIN: You are a good advocate for action and your point is that the government is already heavily involved, so we just need to find the right mix of policies. Travis, I could not tell whether that is also your position.

MR. KAVULLA: Largely so. To the degree that a price on carbon does not get us there, then should we add other policies for market transformation and new technologies?

It is important to have some kind of market mechanism. The UK in some respects has been successful where it has pots of R&D funding as Emma says, but this funding is put out for competition. The big utilities have to compete in order to get that sum of money. If you are going to do some kind of state-level policy that might be an nth best option, then at least make it a competitive solicitation.

MS. PINCHBECK: It was a 2008 Labour government that signed the Climate Change Act. The Act represented a consensus view. It has been right-wing governments that have delivered the policy beneath it.

MR. KAVULLA: Offshore wind is an example of this. You have the Vineyard project off Massachusetts that had to win a competitive solicitation and is coming in relatively low cost.

But compare that to a log-rolling exercise in Virginia where environmentalists teamed up with Dominion to get a state legislative package passed that gave Dominion a no-bid rate-based option for offshore wind that came in at $300 million for a 12-megawatt project resulting in 80¢ per kilowatt hour of electricity, or more than 10 times the result of a competitive solicitation in Massachusetts.

So there are clearly two paths that you can take on these types of policies. One is a form of log-rolling rate-based entitlement that brings out the worst of the capital bias of the regulated utility industry, and the other tries to draw on aspects of liberalization in order to get you lesser cost carbon reductions.

Best Policy Option

MR. MARTIN: Let me bring Bob Inglis back in here. Your website, republicEN.org, says that the group favors conservative and free enterprise solutions to climate change. / *continued page 8*

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The bill would give wind developers another year, through the end of 2020, to start construction of new wind farms to qualify for production tax credits or an investment tax credit at 40% of the full rate. Projects that start construction in 2019 qualify currently for tax credits at this level. The bill would convert the last step of the current phase-out schedule for wind credits into two years so that projects that start construction in 2019 *or 2020* would qualify for tax credits at 40% of the full rate.

Geothermal, biomass, landfill gas, waste-to-energy, incremental hydroelectric and ocean energy projects that are put in service by the end of 2020 would qualify for production tax credits at the full rate. The current deadline is the end of 2017. This is a three-year extension for such projects. Owners of the projects would have the option to claim a 30% investment tax credit instead.

The outlook for tax extenders in the Senate is unclear.

The Senate tax-writing committee was eager earlier in the year to move its own package of tax extenders, but the topic has not made it yet on to the Senate agenda. Lobbyists are focused on several must-pass bills that are expected in the fall as possible vehicles.

The House package includes a series of other extensions.

One affects projects on Indian reservations. Super-accelerated depreciation would be allowed for any such projects that are put in service by the end of 2020. For example, wind and solar projects on reservations could be depreciated on an accelerated basis over three years rather than five years. Gas-fired power plants would be depreciated over nine or 12 years, depending on whether the project has a combined steam cycle. Projects on Indian reservations are required currently to have been in service by the end of 2016 to qualify for such rapid depreciation.

A 20% wage credit could also be claimed on the increased amount of / *continued page 9*

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What does that mean?

MR. INGLIS: The government being just the honest cop on the beat. It says all costs in and all subsidies out. Now compete. Of course "all subsidies out" is hard to get to. For example, is the oil depletion allowance a subsidy or is it not?

There is a libertarian strand in Republicanism that basically says just level the playing field, internalize the negative externalities, and get the government out of the business of favoring one technology over the other.

I spoke at an American Wind Energy Association event and I said, you know I'm going to be the skunk at the garden party because I am going to say when I get there, let's eliminate the production tax credit for wind. They said go ahead if you are really talking about internalizing the cost of burning fossil fuels. If you are, we don't need the production tax credit. In fact, we don't like the near-death experience every time the tax credit comes up for renewal. Just level the playing field and we will fend for ourselves.

MR. MARTIN: Do you favor the government putting a price on carbon?

MR. INGLIS: Yes. We think that is the most efficient way of pricing in the negative externalities.

MR. MARTIN: Travis Kavulla, you complained about hidden carbon taxes. Would you favor an overt carbon tax?

MR. KAVULLA: Yes. I think it is superior to the alternatives. One of the talking points that I use with my Republican friends is that it is an opportunity to get rid of some of the inefficient policies, like the Clean Air Act's purported regulation of carbon dioxide, which would be unnecessary if you transparently priced it, or sub-optimal things like the CAFE standards for transportation. Some of the regulatory clutter could be repealed, I hope, in exchange for a carbon tax. A lot of people are pushing a kind of tax and dividend. I think that is the optimal strategy.

The reality is we are going to get to a place where people are looking for revenue to run the government and, rather than raise general taxes, increasingly carbon may be viewed as an attractive source of that revenue. It might become a kind of political sweet spot. There are regions in the United States that already put a modest price on carbon, mostly through a cap-and-trade regime.

It will be interesting to see how a plan unfolds that the New York ISO is formulating to put a price on carbon in its market and whether the plan gets approved by the Federal Energy Regulatory Commission. Some of the early modeling suggests that the wholesale cost of energy would increase by 50% to 75%, but then the money collected would be rebated back to consumers. If that happens, it could be a really interesting on the ground experiment in how carbon is transparently and robustly priced in the electric power sector.

MR. MARTIN: Emma Pinchbeck, the UK puts a price on carbon currently. Is there a way to explain simply how it works?

MS. PINCHBECK: No. [Laughter] We have a carbon floor price, which the UK government has always kept, even when scaling back green policies, because it is a source of revenue for the UK Treasury.

It is a market-based solution to the problem of climate change. There is no top-down decarbonization target for the UK power sector. It is all done through a mix of carbon pricing and a collective sense of where we need to move as a country. Our carbon floor price is higher than Europe's. It forces the power sector to address hard questions like, "Is it worth keeping this coal-fired power station open for another five years given the current price of renewables?"

MR. MARTIN: Before you go further, is it simply a fuel charge or is it also a cap-and-trade regime within the European community?

MS. PINCHBECK: The part of it that relates to the European scheme is cap-and-trade. The carbon floor price in the UK is a price. So we have an internal carbon price in the UK, but it has a relationship with the EU trading scheme. Please don't ask me what Brexit does to this because I have no idea. [Laughter]

MR. MARTIN: You were forewarned.

MS. PINCHBECK: The UK will be completely off coal by 2025. The carbon price is now fundamental to our energy market design and will remain so going forward as renewables become the incumbent power source.

MR. MARTIN: Bob Inglis, you are a great admirer of a speech that President Kennedy gave in 1962 at Rice University where he called for putting a man on the moon by the end of the decade. We did not have the technology to do it at the time, but we had a Sputnik moment. The Russians had succeeded in launching the first Earth-orbiting satellite. We mobilized our scientists to catch up. You call climate change a slow moving Sputnik moment. Do you think there is a role for agencies like NASA, DARPA and ARPA-E to promote new technology to deal with climate change?

MR. INGLIS: Yes. In fact, I hope that contrary to President Trump's budget, Congress dramatically increases ARPA-E funding. I think that, plus constructive hearings, are the only two things we should ask of the current Congress.

The reason to increase ARPA-E funding is we all live figuratively in Missouri, the show-me state. If you can show me that new technology can help, then you increase my sense of efficacy and I can engage on the climate-change issue. If you tell me that there is nothing I can do about this and I am just hosed, then I give up.

Here is where a schism appears between Republicans and libertarians. My libertarian friends would not like that, but my Republican thought is that only the government can do basic research effectively, and it should do it in a big way. As John Kasich wrote in USA Today earlier this week, we are not talking a little money either. We should be talking big money.

MS. PINCHBECK: Can I tell you a story? I thought that the most inspiring thing about visiting Svalbard, the northernmost inhabited area near the north pole, would be feeling moved by the rugged wilderness, but just outside Svalbard, there is a mountain of ice and it is -23° on a good day. The environment is trying to kill you as soon as you go out the door. About 150 years ago, at the dawn of the last industrial revolution, a group of Victorians wearing nothing but oilskins arrived in Svalbard, looked at a mountain of ice in -23°, discovered there was coal in it and said, "Let's mine it." In those conditions.

They could see the potential to harness technology in a changing global economy, and they were willing to put the resources of the British government and the empire to work to do it. We talked about the problem of climate change, but we are in the midst of another period of transformative economic and technological change, and humanity has made these transitions before. The moon shot analogy is really good for what we are trying to do.

MR. MARTIN: The industrial revolution took hold in the UK starting in the 1840s due to private enterprise.

MS. PINCHBECK: Yes. I work in the private sector. I left NGOs and came back to the private sector because the market is moving and I find that inspiring, but I think we face an existential challenge as a society. The problem does not really suit incrementalism. It doesn't really suit left or right. It is going to have to be an all-of-the-above solution. I am both pro-market and pro-intervention for when there will be market failures.

MR. MARTIN: So there is no time to rely solely on the private sector?

MS. PINCHBECK: That, too, so we have to do this fast. It is about setting ambition and it is about scale. That is where central governments have an advantage because they can invest for scale. They can also take risk. */ continued page 10*

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wages and health care benefits paid to native Americans above whatever base amount the employer paid in 1993. Covered employees need to be members of tribes, live on or near the reservation and do substantially all of their work on the reservation. The credit can only be claimed on the first $20,000 in wages per employee, and there is a cap on the amount the employee can earn. The ability to claim such credits lapsed after 2017. The House bill would let such credits be claimed on compensation paid in 2018, 2019 and 2020.

The bill extends the deadline for making energy efficiency improvements to commercial buildings to qualify for an immediate deduction of the cost. The deduction is limited to $1.80 a square foot. Such improvements had to be completed by 2017 under current law to qualify for the deduction. The new deadline would be the end of 2020.

PRODUCTION TAX CREDITS for some renewable energy projects will be slightly higher in 2019.

Credits for producing refined coal are also increasing.

The credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) are 2.5¢ a kilowatt hour in 2019 compared to 2.4¢ in 2018. They will remain unchanged at 1.2¢ 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 2019 is 13.1168¢ a KWh. The IRS said there will not be any phase out in 2919 because contracted wind electricity prices are 5.18¢ a KWh going into 2019. It said it lacks data */ continued page 11*

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Carbon Tax

MR. MARTIN: Greg Bertelsen, we seem to have a consensus here that putting a price on carbon is an effective policy. The carbon tax you are promoting would collect about $200 billion a year. It would turn it back to the public as a dividend check in an effort to create political support for the program. Tell us more about how it works.

MR. BERTELSEN: A number of you told me this morning that Gina McCarthy, the Obama EPA administrator, spoke here yesterday and suggested that perhaps —

MR. MARTIN: She threw shade on your organization. [Laughter]

MR. BERTELSEN: That's what I hear. If you dig deep enough in Google, you can find a statement from her after the launch of her new organization that if she were still running the US Environmental Protection Agency, she would take in a second a deal to put a direct price on carbon in place of a more complicated regulatory approach.

Those of you who were here yesterday, correct me if I am wrong, but I believe her comment yesterday was that we need a policy that can be explained easily to the American public.

That is why we are so intrigued by the concept of putting a price on carbon by taxing fossil fuel companies. I think everyone is still with us up to this point. We are for putting a tax on fossil fuel companies and then taking all of that money and returning it directly to the American public in the form of either monthly or quarterly dividend checks.

MR. MARTIN: From whom would you collect the tax?

MR. BERTELSEN: From the petroleum industry at the exit point of the refinery. From coal companies at the mine mouth. From natural gas companies perhaps at the gathering station. The goal is to put the tax as far upstream as possible so that the tax is collected from the fewest number of taxpayers at a point where it is administrable. It will send a price signal through the entire economy.

MR. MARTIN: Would the tax be collected from power companies?

MR. BERTELSEN: Under our proposal, no. It would be assessed on fossil fuel companies, presumably some or all of those costs would pass through to utilities when they buy fuel.

MR. MARTIN: How much would the charge be on carbon?

MR. BERTELSEN: We proposed a price starting at $40 a ton, escalating a few percentage points per year above inflation.

To give you a sense of what the modeling shows in terms of emission reductions, if the program starts by 2021, by 2025 we would be about 32% below 2005 levels or well below the US Paris target. But that is just the first part of the equation.

The second part is what do you do with $200 billion in revenue. There are plenty of worthy causes in the climate space and elsewhere for the $200 billion a year. But if this is to be a climate policy first, it must first pass, and then the tax must stay in place and increase with time. You can imagine what might happen with opportunistic politicians challenging incumbents who voted for the gasoline tax or the energy tax. Bob Inglis might be able to speak to this from experience.

We believe it will be a lot harder to challenge supporters if to repeal the energy tax or the gas tax, you must also take away the dividend check that people have been getting in the mail every quarter.

The case study for this is the Alaska permanent fund. This is a program that has been in place for four decades in Alaska. Part of the cost for oil and gas companies to do business in Alaska is they must share some of the revenue from oil and gas production with the citizens of Alaska. Alaska residents get a check every year. It is a hugely popular program. It is politically untouchable. In fact, every now and again a politician tries to touch that pot of money and, every time, he or she is beaten back.

MR. MARTIN: There is another piece of it: a border adjustment to ensure that US manufacturers who had to pay more for fuel will not be disadvantaged. How does that work?

MR. BERTELSEN: It is complex, but simple to explain. Goods that the US exports to countries that do not put a price on carbon

To the extent the Green New Deal pulls Democrats to the left, it will leave room for Republicans to move toward the center.

would be rebated the carbon tax at the US border. Goods coming into the country would be assessed a fee equivalent to what they would have had to bear had a carbon price been in place abroad. The goal is not to design a protectionist program, but the advantage of this for a lot of US industries is the US economy happens to be a lot more carbon efficient than that of China or India.

A border adjustment encourages production to take place in countries where carbon emissions are less, such as the United States. I think this is another key lever for encouraging Republicans, who are more business minded, to come on board.

MR. MARTIN: But who generally are not protectionists. Bob Inglis, you have good political antennae. Does this sound saleable to you?

MR. INGLIS: I think it is.

The dividend creates a political constituency as he was just describing. It also helps address regressivity because a carbon tax by itself is regressive. At republicEN.org, we support the proposal, but we are also a little more ecumenical in terms of the revenue recycling.

If you want to cut individual or corporate income taxes, we are for that. If you want to recycle the revenue through a cut in payroll taxes, we are very much for that. The Congressional Budget Office says that if you cut payroll taxes and put on a carbon tax, the bottom 70 percentile income earners do better under that system than they do today. If you are truly concerned about regressivity, that is the place to go.

Backlash

MR. MARTIN: Carbon and fuel taxes have had to be rolled back in Australia. There is pressure to do so in Canada. Emmanuel Macron in France had to roll back a fuel tax. Do you know enough about those schemes to be able to distinguish them from what is proposed here?

MR. INGLIS: I spent some time two years ago traveling around Australia speaking at the invitation of the Australian Institute to Australian conservatives. Australia did a carbon tax, undid it, did it, undid it. That is a problem for the business community.

Australia does not have the ability to do a border adjustment, which is the key aspect of America's ability to lead. If you want access to this American market, fine. You are going to have to pay our carbon tax on entry unless you have the same-level carbon tax at home. Say that China challenges the border adjustment in the World Trade Organization. We think it loses. If we are right, China, 24 hours after losing in the WTO, will have the same price on carbon dioxide because otherwise its */ continued page 12*

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on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are \$7.173 a ton in 2019. 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 2019. 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 2019 reference price is \$49.23 a ton. A phase out would have started at \$88.92 a ton.

The tax credit amounts were in a notice published in the *Federal Register* on June 6.

SOLAR PROJECTS owned by regulated utilities are not "public utility property" if the electricity is sold at market rates, the IRS confirmed.

By law in Utah, a customer can negotiate directly with a solar developer to buy electricity from a solar facility that the developer plans to build. The customer and developer enter into a power purchase agreement. The solar facility and contract are then sold by the developer to the utility.

A concern when a regulated utility owns a solar facility is whether an investment tax credit and accelerated depreciation can be claimed on it.

Utilities could not claim investment tax credits on solar facilities before 2008 as Congress worried that utilities would squeeze out independent solar developers. Since then, an ITC can be claimed, but utilities must still clear one more hurdle. Utility ownership will turn the solar facility into "public utility property" if the rates at which the electricity is sold are "established or approved" by a public utility commission on a rate-of-return basis.

In a game of chicken in 1969 with state regulators, the utilities asked Congress to deny them accelerated depreciation on "public utility property" if they are forced by regulators to pass through these tax benefits to ratepayers too quickly. Any */ continued page 13*

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exporters will pay a tax on entry into the United States that goes to Washington and that could have been collected at home and been retained in Beijing.

Then you have the whole world following. No international agreement is needed. To the people on right-wing talk radio, did you hear that? No international agreement. No bowing and scraping at the United Nations. Just a bold move by the United States that says we are going to lead and now, rest of the countries in the world, decide what you want to do in your interest.

MS. PINCHBECK: I have spent the last seven years having an argument with a government that is right wing about climate policy and —

MR. MARTIN: Your right wing is our center to left.

A coalition of business groups and establishment Republicans is lining up behind a carbon tax.

MS. PINCHBECK: Well, I don't know. We are doing Brexit, and that's pretty right wing for the moment.

This is about why I am skeptical about carbon pricing on its own as a solution. From experience with both markets and people, we do not always do the economically efficient thing. Like, ever.

Take me, for example. I work in energy policy. My husband is always hectoring me to turn the lights off. We are humans, and we behave in strange ways.

There is no such thing as a subsidy for renewables currently in the UK. Renewables are winning on a pure price point. They are the cheapest form of generation to build. That said, we cannot build onshore wind or storage very easily on just merchant models alone for various reasons, including that we do not price things transparently in our economy. Financiers in the City also require a long-term guaranteed return on their investments. They want to see a floor price, even a subsidy free one.

MR. MARTIN: So we don't need the government involved?

MS. PINCHBECK: Not so fast. We need the government to correct market failures.

The reason that people are hostile in France, for example, to carbon pricing is that it was sold as a climate change policy at a time when Macron is hated, and it was tied to a whole load of other populist sentiment against things like EU intervention. It is seen as a kind of globalist interventionist policy in an era of rising nationalist sentiment. Macron did not bother to communicate it effectively. He just thought he could say climate change. Government policies need to be more effectively communicated.

Markets do not always follow economic efficiency. They do things for other reasons, too. That is where you get market failures and sometimes where you need policy.

Utility Business Model

MR. MARTIN: We are winding down. I have two more questions.

Starting with PG&E, Travis Kavulla, you are a former utility regulator. You have said the PG&E bankruptcy raises in the minds of regulators whether utilities should act as insurance companies. Regulators must decide whether the cost of rare events like wildfires and hurricanes should be socialized by passing through the costs to ratepayers or should be borne by utility creditors and shareholders.

What do you think the PG&E bankruptcy will mean for the basic utility business model going forward?

MR. KAVULLA: It is hard to draw generic lessons from California, but there is one lesson that I think can be drawn, which is how vulnerable big central-station networks are to black-swan events like wildfires in the West and hurricanes in the coastal areas.

I would usually say to most people that the 9% and 10% returns on equity that regulators dole out to largely risk-free companies are supernormal and excessive. But here you have found, once in a blue moon, a regulated firm whose return on equity actually understates, evidently, its level of risk, which is kind of surprising. I had always been under the assumption that we were overcompensating these people for their risk.

If you actually expect them to bear climate risk, then their ROE is going to have to be substantially higher. In a sector where California law puts much of the liability on California utilities and where utilities have no meaningful recovery opportunity from their ratepayers, you are going to have to nearly double their returns on equity. It raises questions about the optimality of that form of regulation versus creating something like a state-backed loss fund or trying to get the insurance community involved and reinsuring some of this risk.

It is something that anyone who operates a large utility network should be paying attention to, notwithstanding the weirdness of California public policy having contributed to the problem.

MR. MARTIN: Are there any questions from the audience?

MR. HAYMAKER: Tom Haymaker with Clark Public Utilities in the state of Washington. I listened to the suggestion that carbon taxes might be the most efficient or best way to get greenhouse gas reductions. Washington state is one of the most environmentally conscious states in the Union. We had two public referenda on a carbon tax, and both times the tax lost. In fact, the proposal lost in all but two counties in the state. So I am having a cognitive dissonance moment here, where I hear you guys — and I believe you are right -— say a carbon tax that is the best way to do it, but the voters, even in the state of Washington, are saying, "We don't want such a tax." How do we put those things together?

MR. MARTIN: Let me ask before our panel answers. Did you vote for it? [Laughter]

MR. HAYMAKER: That's none of your business.

MR. MARTIN: Cognitive dissonance. Go ahead, Greg Bertelsen.

MR. BERTELSEN: Two quick thoughts. First, not all carbon tax proposals are created equal. Without getting into the details, I would argue there were serious flaws with the design of the Washington state carbon tax. Second, the vote underlines the importance of national policy being consensus-based. In Washington state, you had big oil against big environment, and it got super-ugly and super-expensive, which is why we are starting with the opposite approach. We are starting with big oil and big environment working together to avoid that very collision.

MR. KAVULLA: Keith, can I add / *continued page 14*

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sharing of benefits with ratepayers must not be faster than is allowed under a "normalization" method of accounting. Normalization also applies to the investment tax credit.

The IRS confirmed in a private letter ruling made public in June that solar facilities that utilities acquire under a Utah-like program are not "public utility property" since the electricity is sold at rates that the customer negotiates directly with the solar developer rather than at regulated rates. The ruling is Private Letter Ruling 201923019.

The conclusion is not a surprise, but the ruling may still prove helpful in some tax equity transactions. Not every utility is able to use the tax benefits. Some regulated utilities are entering into tax equity transactions to convert the tax benefits into current cash that can be used to help pay the project cost. There is a premium on structures that avoid subjecting the tax benefits to normalization.

REFINED COAL tax credits drew fire from three US Senators in early June.

Senators Elizabeth Warren (D-Massachusetts), Sheldon Whitehouse (D-Rhode Island) and Sherrod Brown (D-Ohio) sent a letter to the IRS commissioner urging him to require refined coal producers to use CEMS field testing on site to prove actual emissions reductions rather than accept laboratory results from burning coal samples in pilot-scale test furnaces.

The US government offers production tax credits of $7.173 a ton as an inducement to produce refined coal. Refined coal is coal that has been treated with chemicals to make it less polluting. To qualify for tax credits, nitrogen oxide emissions must be reduced by at least 20% compared to burning regular coal and sulfur dioxide or mercury emissions must be reduced by at least 40%. Tax credits can be claimed for 10 years after the equipment for treating coal is first put in service. Such equipment had to be in service by December 2011 to qualify. / *continued page 15*

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quickly? The fatal flaw in state initiatives on carbon taxation is that you cannot do a border adjustment. If the governor of Illinois wants to solve his budget problems, he could try to have the state impose a carbon tax. Billboards would spring up immediately around Chicago that say "Illinoised yet? Move to Indiana." If you put on a carbon tax within a state, the leakage to the neighboring states is massive. That is why it only works as a federal policy.

MR. MARTIN: Another question, this time from Kevin Lynch with Avangrid Renewables.

MR. LYNCH: Thanks, Keith. Along those lines, I don't have a lot of confidence that the American voter can wait a year for the dividend after the tax is imposed, so I am wondering if the proposal is backwards. Should we do the dividend and then the tax?

MR. BERTELSEN: The Climate Leadership Council agrees with you. What we propose doing is to pay the first dividend before the tax hits, so that the first thing you see as part of the program is a check in the mail.

MR. KAVULLA: And to reiterate, notwithstanding that it is insane to regulate locally a globally diffuse gas, most action on carbon pricing in the United States is on a regional and state level. The New York ISO is in all likelihood going to make a filing with FERC to impose a carbon price with a retail-side emanation in the form of a rebate on people's bills of the incremental revenue.

To the degree that we believe in the laboratory-of-democracy kind of approach in America, it is good to vet some of these policy ideas on the ground like that. It is a much fairer system. Not to pile in on Washington state, but one of the biggest objections to the carbon tax on the voter ballot was that the proceeds would go into a governor-controlled slush fund. I think the UK term for it is a quango. There was not a lot of political confidence in that. It did not pass for all sorts of reasons, but if you really wanted to be critical, it looked like a crass power play rather than a bona-fide good-spirited carbon price.

And hilariously, a tax promoted by a libertarian academic was opposed by the Sierra Club, because it didn't do enough for "social justice" and all the kind of rent-seeking that usually attaches to green energy policies. So hilariously, you had a kind of libertarian purist thing that was opposed by the environmental left.

MS. PINCHBECK: Do you think it is because people fundamentally do not like to feel that things are being done to them, and we need to do much better at explaining that the impacts of climate change are coming for you whether you like it or not? It will intervene in your life, and here are the solutions can be done for you: for example, the green energy jobs that we are seeing created in the UK, the wealth creation, the regional investment and other community benefits that come off the backs of our wind farms.

The polling on climate change is consistent in the UK: roughly 80% of the public thinks we should do more, 65+% think we should do more to encourage in renewables. Our electorate remains fractured politically, but what has shifted is the economic case. People understand that this industry and this change produce benefits for them.

MR. MARTIN: A signal moment in the US was the Super Bowl commercial for Budweiser.

MS. PINCHBECK: I saw that, with the dog!

MR. MARTIN: You had an American beer company touting how it uses green energy in order to sell beer. Consumer change is a leading indicator in government policy.

There is time for only one more audience question.

MS. JOHNSON: Jessica Johnson from Avangrid Renewables. I'm interested in the idea of a carbon tax. I wonder whether someone can talk about its relation to the existing subsidies that the oil and gas industry receives from the federal government.

MR. KAVULLA: I think you are looking at a chorus of people who oppose, maybe not all types of subsidies, but probably that subsidy at the very least. Subsidies create hidden costs. The one you mentioned is a real problem.

If any kind of carbon tax is adopted, it would also require attendant regulatory reforms that clear out some of the clutter that directs money to different sectors, some to renewables and some to oil and gas producers. The opportunity is ripe for a reform.

MR. INGLIS: While a carbon tax and clearing out all energy subsidies are the ideal policy, the best climate policy is the one that can pass. For every existing subsidy, renewable or fossil, there is a member of Congress who is a constituent for that tax provision and that leads to complications. It gets ugly quickly. The ideal and the feasible do not always overlap perfectly.

MR. MARTIN: Short comment. We have to close.

MR. COLLADO: Pablo Callado with Iberdrola. My comment is that it does not help renewables to keep talking about subsidies. We need to banish that word from our speech. We are talking about the cheapest technology. All we need is long-term visibility into the revenues to make sure our projects are bankable.

MS. PINCHBECK: It is rare at the moment as a UK citizen that I get to feel smug about anything, because you have all read the Brexit news.

However, the power sector transition in the UK means that we are a bit further ahead on the decarbonization curve than others. With respect to the gentlemen on stage, I rarely think about climate change or any kind of top-down policy any more. I think about how best to accelerate and support a market that is moving by itself. I have not had a conversation about whether we need to subsidize renewables in about three years, because when I walk into a government department now with the nuclear industry and the oil and gas lobby, I am the cheapest form of energy generation. The only issue is whether to accelerate a change that is already occurring and is being driven by the private sector.

All of my work at the moment is on the demand side. It is on smart technology, homes, transport, integration with the wider energy system, and the tricky stuff. We have won a lot of these arguments. It might not feel like it, but the policy debate is over.

MR. KAVULLA: And from a US power market perspective, there are plenty of situations where the going-forward costs of existing resources exceed the cost of new renewable entry. And yet the existing power plants stay operational. Why is that?

It is not because government intervention is there to promote renewables. It is because regulation and policy retain capital inefficiencies. That is the paradox of all this talk about the Green New Deal. If you had a customer empowerment act, something that promoted liberalization in the power sector and competitive entry, you would actually discipline it a lot. It is regulation and policy that maintain some of the inefficiencies in the power sector. Left alone, customers would gravitate more quickly to renewables.

US Divisions

MR. MARTIN: I want to wrap up with this. Bob Inglis, you gave a fascinating TED talk last year in Boston.

You had a refrain. You kept repeating, "Suppose you are a conservative member of the House," and you followed it each time with an observation. For example, you said you worried while in the House about the fire of populist nationalism. Those who play with fire cannot control it. Pitchforks and torches are not great building tools.

You said you would go to county meetings in your Congressional district when you were running for reelection, and the voters would want to hear you say that there is a closet Muslim socialist in the White House. You were unwilling to say it.

You lost your seat. And yet you came / *continued page 16*

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Refined coal producers must prove emissions reductions at the outset by comparing the emissions produced from burning both refined coal and regular coal at the actual power plant using a continuous emissions monitoring system or by analyzing emissions from test burns of both types of coal at a laboratory. Most testing is done at a test facility at the University of North Dakota.

IRS rules then require the emissions to be checked every six months. However, the required emissions reductions are assumed to have been maintained as long as the sulfur and mercury content of both the refined coal and regular coal are within 10% of what was observed when emissions testing was done at the outset.

The IRS has been challenging aggressively structured tax equity transactions involving refined coal credits. (For earlier coverage, see "Refined Coal" in the April 2018 *NewsWire*.) However, the agency has been reluctant to spend time rewriting the basic rules it has been using because the tax credits have nearly expired.

Two researchers at Resources for the Future said in a 37-page report in early June that they found no evidence that any coal-fired power plant is achieving the required emissions reductions in fact in both NOx and sulfur dioxide or mercury. Actual emissions at less than 20% of plants were reaching the NOx target, and emissions at none of the plants that reached the NOx target also reached the sulfur dioxide or mercury target.

The two researchers did regression analyses comparing emissions at coal-burning power plants accounting for 90% of coal usage in the United States and found average emissions reductions using refined coal of 12.5% for NOx, 2.3% for sulfur dioxide and 24.1% for mercury.

Refined coal accounts for roughly 20% of coal used in the US power sector.

A bill introduced in the Senate in May by the two North Dakota Senators would allow another 10 years of tax / *continued page 17*

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away from it all with your American optimism intact. What makes you think this country is going to be able to pull itself together again? We are so divided politically.

MR. INGLIS: Well, here we are in Arizona, and to quote my very dear friend, former Arizona Senator Jeff Flake, "The fever will break."

Tom Friedman described the American DNA in *The World is Flat*. This is a country young enough and brash enough to believe that every problem has a solution. Every once in a while we get down on our luck and we feel put-upon, and we will listen to somebody telling us a down-in-the-mouth tale.

But eventually we get tired of it. I think we are in the process now of tiring of it. We will return to our basic selves. Sir Winston Churchill never lost hope in us during the early days of World War II when Britain battled alone against the Nazis and night after night, the German bombers pounded London and other cities. He assured the British people, "You can always count on the Americans to do the right thing after they've exhausted every other option."

We are in the process now, having had our pity party, the Great Recession and feeling really bad about ourselves, we are going to come out of it. The fever will break.

Opportunity Zones and Renewable Energy

by Keith Martin and Ben Storch, in Washington

Opportunity zones have been something of a disappointment so far to renewable energy developers. Developers have been looking at them as a possible way to raise equity for their projects.

The US government made a limited-time offer in the tax reform bill at the end of 2017 to investors sitting on assets that have appreciated in value. The offer has two parts.

Part one is if an investor will sell assets and reinvest the capital gain in a business in a low-income area called an "opportunity zone," then taxes on the asset sale can be deferred until the end of 2026. When the taxes are ultimately collected, the government will tax only 90% of the reinvested capital 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% of the reinvested capital gain if the new investment in the opportunity zone has been held, by 2026, for at least seven years. Thus, the investment in the opportunity zone would have to be made by the end of 2019 to get the maximum benefit from this part of the offer.

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 the gain on the new investment when it is sold.

Renewable energy developers have viewed this as presenting two opportunities.

One is a chance to raise equity more cheaply from investors with big capital gains from recent asset sales. An investor must reinvest the capital gain within 180 days in an opportunity zone fund that invests, in turn, in businesses in opportunity zones.

The other opportunity may be for renewable energy developers who have sold projects, including into tax equity vehicles at a gain as a way of stepping up the tax basis for investment credit purposes, to defer tax on the gain by plowing the money, within 180 days, into another project the developer has under development. However, the sales would have to produce capital gains rather than ordinary income for there to be any capital gain to reinvest. Developers may be considered to be selling inventory, which produces ordinary income.

Opportunity zones are low-income areas. State governors had until April 20, 2018 to nominate areas within their states to be designated. In all, roughly 8,700 such zones have been designated, or 12% of US Census tracts. Renewable energy projects tend to be in rural areas that are often opportunity zones. A comprehensive list of all the designated zones can be found at www.cdfifund.gov/Pages/Opportunity-Zones.

The Internal Revenue Service issued proposed regulations in October 2018, and then updated them in April 2019, to fill in detail about how the zones are supposed to work. The regulations are dense and full of traps not only for the unwary, but also for the wary. Tapping into opportunity zone funding for a renewable energy project is like trying to navigate through an intricately constructed maze. The zones work best for real estate projects. They are harder to make work for investments in operating businesses. Twenty opportunity zone funds have announced plans to raise funds to invest at least partly in renewable energy projects. To date, none of them appears to have closed on such an investment.

Into the Maze

There are four main impediments for renewable energy projects to take advantage of opportunity zone funding. Some additional guidance would be helpful from the IRS.

Renewable energy projects are owned by legal entities.

An investor who has just sold assets at a gain has 180 days to invest the gain in a fund that, in turn, invests the money into businesses in opportunity zones. Almost by definition, since any investment in a renewable energy project will be made alongside the sponsor in a legal entity that owns the project, the investment will be considered to have been made in a "fund." The fund must be certified as a "qualified opportunity fund" when the investment is made.

Funds self-certify by filing a Form 8996 with the IRS. The form is filed with the fund's tax return for the first year the fund will be a qualified fund: for example, in 2020 for a fund that will first qualify in 2019.

The fund can specify the first month it wants to be considered a qualified fund. A clock then starts to run on when the fund must pass a 90% assets test. This is the first difficult turn in the maze.

At least 90% of the fund's assets must be "qualified opportunity zone property" or "QOZ property" each tax year.

There are generally two test dates each year for determining compliance with the 90% test: June 30 and December 31 for a fund using a calendar tax year, and the results on the two dates are averaged. However, unless the fund declares itself qualified as of January 1 of a year, its first year will */ continued page 18*

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credits for existing refined coal facilities and reopen the window for another three years from 2019 through 2021 for additional refined coal facilities to be put in service to qualify for tax credits. A similar bill was introduced in both the House and Senate in 2018, but failed to advance.

PLEDGING A FOREIGN SUBSIDIARY'S ASSETS to guarantee repayment of a loan to the parent company triggered income taxes.

The Susquehanna International Group, a quantitative trading firm, borrowed $1.5 billion from Merrill Lynch in 2007. Merrill Lynch insisted that the loan be guaranteed by more than 30 affiliated companies, including two offshore companies that were subsidiaries of SIH Partners LLLP, a partnership that was another affiliated entity.

The two offshore companies were considered "controlled foreign corporations" for US tax purposes, meaning that they were owned more than 50% by vote or value by US shareholders.

Before 2018, the United States did not tax US shareholders on the earnings of their offshore subsidiaries until the earnings were repatriated, but there were exceptions. One exception was it would look through the offshore subsidiary and tax any dividends, interest or other passive income received by the offshore subsidiary without waiting for it to be repatriated. Another exception was it would treat earnings parked in the subsidiary as having been repatriated if the subsidiary guaranteed repayment of a loan to a US affiliate.

Merrill Lynch insisted that the two offshore companies had to be included in the group of subsidiaries guaranteeing repayment in order to "ring fence" the transaction by preventing US subsidiaries from shifting assets overseas to move them outside the pool of assets securing repayment of the loan.

The two offshore companies paid actual dividends to the SIH */ continued page 19*

Opportunity Zones

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have less than 12 months. In that case, the first test date is six months after the first day the fund considers itself qualified or, if shorter, whatever time is left in the first tax year. If there is room for a second test date the first year, it is the last day of the year.

The fund can choose what date it wants to declare it is qualified. However, once it does so, it has six months to pass a 90% assets test. It must specify a date no later than when it takes the investor's money.

A major issue is that cash being held for use in a project still under development will generally count as a bad asset under the 90% test. However, if the fund invests the money into a subsidiary partnership or corporation, instead of developing the project directly, then this will buy up to 31 months to expend the cash without it counting against the 90% assets test in the meantime.

First-Tier Partnership

Therefore, assume the fund will interpose a partnership between itself and the project. This will let the fund treat the partnership interest as QOZ property on each six-month test date if three things are true.

First, the fund must acquire the partnership interest solely in exchange for cash. It should make a cash contribution to the partnership for an interest rather than pay the sponsor for an interest. The problem with paying the sponsor is this is treated for tax purposes as the purchase of an undivided interest in the project assets and contribution of that share of the project assets to the partnership in exchange for an interest in the partnership. In other words, the fund may not have acquired its partnership interest solely for cash.

Second, the partnership must be a "qualified opportunity zone business" or "QOZ business" when the fund acquires an interest in the partnership "or, in the case of a new partnership, the partnership was being organized for purposes of being a qualified opportunity zone business." The partnership can buy time, if it is not already in business, by having a detailed "written schedule" for getting to QOZ business status within 31 months.

Finally, during at least 90% of the period the fund owns an interest in the partnership, the partnership must actually be a QOZ business. The fund can buy time by having a detailed written schedule for getting to a QOZ business status within 31 months.

Diving Below the Partnership

Consider a simplified example where the first-tier partnership is the sole asset of the fund. The fund has to satisfy a 90% assets test within six months. The partnership interest is a good asset if the interest in the partnership is acquired solely for cash and the partnership has a plan to become a qualified opportunity zone business within 31 months.

What does it take to be a QOZ business by the end of the 31 months?

The partnership must have jumped through a series of hoops.

First, it must pass a tangible assets test.

At least 70% of its tangible assets must be acquired from third parties that are unrelated to the partnership. Two parties are related if there is more than 20% overlapping ownership. Thus, using a related construction contractor to build the project may be a problem.

The challenge is even greater because the fund cannot have tiers of partnerships below it. Therefore, the partnership immediately below the fund must also act as the tax equity partnership if the renewable energy project will be financed in the tax equity market. In solar tax equity deals, the project company is often sold to the tax equity partnership for the appraised value as a way of stepping up the tax basis for calculating the investment tax credit. Any such sale would have to be by someone who will not have more than a 20% interest in the partnership.

> Opportunity zones have been something of a disappointment so far to renewable energy developers.

There are still more requirements to pass the tangible assets test. The project must be brand new when the partnership puts it into service. At least 70% of the equipment and other tangible property owned by the partnership must be used in the zone during at least 90% of the period the partnership owns them. Also, the partnership cannot have an option to buy any site it leases for a fixed price, and any site lease must have arm's-length terms.

Next, the partnership must pass a 50% gross income test each tax year. The partnership cannot wait until the end of the 31 months to start passing it.

At least 50% of the partnership's gross income each tax year must be earned from the "active conduct of a trade or business" by the partnership inside the zone.

When the first set of IRS regulations was issued in October 2018, they did not seem to leave room for businesses to qualify that make goods inside the zone and sell them outside. The income in such cases may have been considered earned outside the zone.

The April 2019 regulations tried to address this problem, but issues remain when it comes to utility-scale power projects.

There are three "safe harbors" that can be used to demonstrate that at least 50% of gross income is earned in the zone. The first two treat income as earned inside or outside the zone based on where the work is done to earn the income. Safe harbor #1 looks at the division of compensation to employees and independent contractors who help with the project inside and outside the zone, and safe harbor #2 looks at the breakdown of hours. These safe harbors may be hard to meet where company management and the lawyers, permitting specialists, independent engineers and other consultants who work on the project are outside the zone.

Under safe harbor #3, the 50% gross income test is met if the "tangible property [located] and the management or operational functions performed" in the zone are each necessary for generating at least 50% of gross income. This is another place where more IRS guidance would be helpful. It is unclear whether the word "operational" is offered as a synonym for management or as a separate category and, if the latter, what the IRS has in mind.

Some tax equity deals in the solar market are structured as inverted leases. In that case, the partnership immediately below the fund would lease the project to a tax equity investor. The partnership would make an election to pass through the investment tax credit to the tax equity investor as lessee.

It is not clear whether the lease can be a traditional "triple net lease," meaning a lease where the lessee / *continued page 20*

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partnership that owned them in 2011. However, on audit, the IRS determined that their entire earnings should have been treated as distributed to the partnership in 2007 when the two companies guaranteed repayment of the loan.

This led to a back tax bill of $378.3 million.

To add insult to injury, the IRS said the earnings had to be taxed at the full 35% corporate tax rate rather than the lower 15% rate in effect at the time for "qualified dividend income" on grounds that the repatriated earnings were not actual dividends.

The SIH partnership lost in both the US Tax Court and on appeal.

The case is *SIH Partners LLLP v. Commissioner*. The US appeals court released its decision in May.

The case is a reminder for US companies with earnings parked in offshore subsidiaries to exercise caution before doing anything that might be considered a use of the earnings in the United States. Any investment of the earnings in the United States may be considered a deemed repatriation. An asset pledge to secure repayment of a loan to a US company is considered such an investment.

The rules in this area have become more complicated since the US tax reforms in late 2017. The US has moved part way to a territorial tax system where US corporations are taxed only on income from US sources. An asset pledge by a foreign subsidiary to guarantee repayment of a loan to a US parent corporation is generally no longer a concern. However, some vestiges of the old regime remain as potential traps.

AN ABANDONMENT LOSS can be claimed on a cancelled nuclear power plant, even though the utility plans to pursue recovery of its costs through a rate increase.

Section 165 of the US tax code allows any loss sustained during the year to be deducted as long as it is "not / *continued page 21*

Opportunity Zones

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is responsible for maintaining the project, buying casualty insurance and paying property taxes during the period the lease is in place.

The proposed IRS regulations say that merely entering into a "triple net lease" of real property to a third party is not the active conduct of a trade or business by the lessor partnership in the zone. Some counsel recommend making the inverted lease into the equivalent of where someone leases a car and driver rather than just the car. This will convert the lease from a triple net lease into an operating lease, but also create tension with a tax equity investor as to whether it has enough risk to be a true lessee of the solar project. The tax equity investor must be a true lessee to be able to claim the investment tax credit on a project.

More Hoops

There is still more to be done by the end of the 31 months.

Third, the partnership must be in a position by the end of the period to pass a 40% intangibles use test.

The partnership must use at least 40% of its intangible property inside the zone. Power contracts are intangible property as is software in computers, outside the zone, for monitoring and operating the equipment inside. It is not clear where a power contract is considered used if the power is delivered to a point of interconnection with a utility offtaker outside the zone.

Fourth, the "nonqualified financial property" owned by the partnership cannot amount to 5% or more of its assets by "unadjusted asset basis."

This is measured by looking at what the partnership paid for the assets. Partnership interests and forward contracts are considered nonqualified financial assets. (A power contract is a forward contract.) Therefore, as a practical matter, the first-tier partnership cannot own an interest in another partnership, and the amount it is considered to have paid for a power purchase agreement and other financial instruments cannot amount to 5% or more of the total amount paid to buy the project rights plus build the project.

31 Months

The first-tier partnership must have a "written schedule" for spending its "working capital" — cash — on getting to a position, within 31 months, where it will pass the tests to be a QOZ business.

The schedule must be a detailed plan showing what will be acquired with the cash. The cash must be used in a manner "substantially consistent" with the schedule.

Notwithstanding the 31 months, the partnership must pass the 50% gross income test in each tax year, including year 1. However, the partnership gets a pass during the 31 months on use of at least 40% of its intangible assets in the zone. It also gets to ignore the cash it plans to spend under the schedule in applying the 5% limit on "nonqualified financial property." (Cash beyond the amounts that the partnership plans to spend under the schedule is nonqualified financial property.) Finally, during the 31-month start-up period, the assets contemplated by the written expenditure schedule count toward the 70% tangible assets test even if expenditure has not yet occurred.

Summing Up

The IRS has made tapping into opportunity zone dollars complicated.

Probably the biggest challenge is that it is not clear whether a partnership owning a utility-scale renewable energy project can pass the 50% gross income test. It is unclear whether a wind or solar project that brings development, but few jobs other than construction labor, to a zone is consistent with what the IRS is trying to encourage.

Moving back up to the fund level, once a fund declares itself qualified, failure to pass the 90% asset test by the next six-month test date will subject the fund to a significant penalty: each month during which a fund was self-certified as qualified will be scrutinized to determine the amount by which the fund fell below the 90% standard, and this amount will be multiplied by 3% plus the federal short-term interest rate for each shortfall month. The penalty is currently 5.35%. On top of the penalty, a fund could owe an indemnity to investors for lost tax benefits if it incorrectly self-certified, depending on what representations are made to the investors. These challenges have made the market slow to take the plunge.

There has been a debate among potential fund investors about whether choosing tax deferral is sensible since tax rates may be at a low. Rates could increase in the next Congress if the Democrats win the 2020 elections. They could increase by 2026, even if Republicans retain control of the Senate or White House, because of the ballooning federal budget deficit.

Because of the delay getting the concepts ironed out, the Senate sponsors of the opportunity zone provision are now urging Congress to push back the 2026 date when deferred taxes come due. There will not be enough time for anyone investing after 2019 to have held an opportunity zone investment for at least seven years to qualify to be taxed on only 85% of the invested deferred gain. ◎

Covariance Risk: What it is and How to Manage it

by Lee Taylor, with REsurety in Boston

Project sponsors, banks and tax equity investors in transactions with hedges may be overlooking some risks that wind projects are bearing. Each risk should be borne by the party best able to manage it. In some deals, this may not be happening.

One such risk is covariance risk.

There has been a fundamental shift in how electricity is sold by independent generators. As utilities cut back on the amount of electricity they are buying under long-term contracts from independent generators, financial parties, like banks and commodities firms, entered the market to buy power. Utilities have tended to buy "as-generated power," meaning they pay a fixed price regardless of how much power is generated and — critically — when it is generated. In contrast, financial parties typically buy power in fixed blocks: with a set volume of power every hour over the life of the contract.

Financial parties buy power this way either so that they can match up with a predictable load or, more commonly, so that they have a known volume of power to sell to the physical consumers of electricity.

Selling fixed volumes of power in every hour of a contract creates challenges for an electricity supplier like a wind farm. The owner of the project does not know, and has no control over, how much electricity it will produce in any given hour, and even though there are seasonal and diurnal averages, what actually happens in any hour is highly variable.

Covariance

"Covariance risk" is the risk that a project will have a strong (typically negative) relationship between generation and price — so an hour of abnormally high generation will correspond to a low power price, and vice versa. While this condition can limit the value of power from a merchant wind farm relative to baseload energy, it is particularly challenging when the project has made fixed hourly delivery commitments (physically or financially) as the project not only misses out on revenues during high price hours, but is in fact a buyer of energy during those hours due to a need to purchase any shortfall / continued page 22

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compensated for by insurance or otherwise." Determining the year the loss occurs can sometimes be challenging. There must be an identifiable event that confirms a project has been permanently abandoned.

A utility owned an undivided interest in a nuclear power project. The project was 11 years in the making. It was beset by large cost overruns. The construction contractor went bankrupt and was likely to disavow the contract in bankruptcy, depriving the owners of the benefit of the fixed-price terms and delay penalties. Construction delays meant that the project was no longer expected to be completed in time to qualify for production tax credits the US government offers as an inducement to build new nuclear power plants.

The other owners of the plant unilaterally decided to suspend construction. The utility then announced publicly that it was cancelling the project. There was significant media coverage of the announcement.

A partly built nuclear power plant cannot simply be boarded up. Construction is heavily regulated. So is dismantling the work.

The utility informed the public utility commission, withdrew an application for a loan guarantee from the US Department of Energy, stopped work, began demobilizing the construction crews, adopted a board resolution permanently abandoning the project, cancelled its builder's risk insurance and took a series of other steps in year 11 to cancel the project.

The IRS told the utility in a private letter ruling that that it could take an abandonment loss in year 11, notwithstanding that unwinding everything would take time.

It said the fact that the utility was seeking reimbursement for its costs through a rate increase does not mean the utility will be compensated for the loss "through insurance or otherwise." The rates are not direct compensation for the loss. Rather, the public utility commission takes into account many factors in deciding how best to / continued page 23

Covariance Risk

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between its hourly commitment and its hourly generation.

Chances are the reason the project came up short is a shortage of fuel: the wind died. And if the wind dies at a single project, it likely died at all of the neighboring projects — which means overall energy supply to the region has fallen, driving up energy prices — so the cost to cover the generation shortfall will be expensive.

A balance-of-hedge product is being used in some renewable energy projects to cover covariance risk.

To put this condition in financial terms, the current cap on energy price in ERCOT during a supply scarcity event is $9,000. Suppose a large wind farm in ERCOT has committed to sell 50 megawatt hours of electricity during a certain hour for a fixed price of $20 a MWh. It is a hot day in August. The wind dies and power prices spike to $9,000 a MWh in that hour. The project is at risk of having to buy 50 MWh at $9,000 each just to sell them under the existing contract for $20 each — a net cost to the project of $449,000 for a single hour.

The insurance markets are typically better positioned to absorb that kind of risk than are independent generators because insurers have a much greater capacity to absorb and diversify that risk.

An insurer can hold wind risk in Texas, solar risk in Australia, hydro risk in Uruguay, and so on, with the idea that extreme weather patterns are unlikely to hit every area simultaneously. The ability to diversify the risk makes the insurer the party best able to manage location-specific, weather-driven risks.

Balance of Hedge

Renewable generation projects can manage covariance risk through a hedging product called a "balance of hedge."

The balance-of-hedge product is designed for projects that will sign or have already signed a hedge with a bank or commodity trader to swap floating market prices for fixed prices on fixed volumes of power. It transfers the risk of being short during high prices and long during low prices. The insurer will assign an expected value to all of the residual excess short and long positions. Because of the enormous amount of potential volatility, the insurer will price the risk below the expected value so that it should make money for the insurer during an "average" weather year, but will eliminate the project's exposure to extreme weather conditions.

For example, July 2018 was very hot in Texas. Power prices spiked during a period when wind speeds were low. Anyone with a bank hedge that month probably had a rough month. A balance of hedge smooths out the pattern of cash flow for a project with a fixed-quantity price hedge. The underlying hedge converts the floating revenue for a project selling its electricity into ERCOT into a fixed revenue stream, but if it is a fixed-volume hedge, it does not protect a project from coming up short on the fixed volume that the project has promised and having to cover the shortfall in floating revenue owed under the hedge. The balance of hedge covers this risk.

There may be only a limited appetite for a balance of hedge at the project level for an existing tax equity deal. The tax equity investor and lender have already underwritten the transaction based on their evaluations of the power contract and hedge. Most sponsors would do better to have the project company sign the balance-of-hedge contract with the insurance company when the tax equity is first put in place. Doing it later requires consent from the tax equity investor, who may be reluctant to reopen a transaction, especially as it may require a re-marking of the position.

From a credit perspective, a letter of credit is typically used as collateral for the balance of hedge. This is often posted at the sponsor level. However, if the sponsor lacks access to an LC facility or wants to offer a lien instead, then the lien must be harmonized with the lien-based collateral that has probably been provided to the bank that is the counterparty to the main bank hedge. Anyone entering into a bank hedge without putting the balance of hedge in place at the same time should negotiate for the ability to use incremental liens as collateral for the insurance company that is the counterparty under any balance of hedge put in place later.

REsurety is not an insurer. We support balance of hedge transactions by providing analyses to insurers who use those analyses to offer and set the price of balance-of-hedge products. While other insurers are working to enter the market, the vast majority of balance-of-hedge contracts — and other related products — have been offered through a partnership between Allianz Risk Transfer and Nephila Climate.

Assessing the Value

A white paper on our website called "The P99 Hedge that Wasn't" looks at the hourly performance of every operating wind farm in Texas. We were able to use this data to analyze how a wind farm that purchased a bank hedge would have performed historically, including through the 2014 polar vortex, the 2011 heat wave and other major weather-driven events.

That said, a perfect view of the past cannot guarantee future performance. A good example occurred when coal plants dropped out of the ERCOT generation fleet in 2017 and the ERCOT reserve margin shrank, increasing the likelihood of high price events during low wind periods. Predicting how pricing will be affected in a market with less thermal generation and much more wind and solar is hard. You are predicting how various weather and commodity conditions will interact with a generation stack that has never existed before. Every month there are more wind farms in Texas than ever before. We spend a lot of time looking at how projects and markets performed over the last five or six years under high and low gas prices, high and low temperatures and high and low wind speeds, and analyzing how this is likely to change over time.

That depth of analysis is critical to insurers' ability to underwrite balance-of-hedge and related products. Fundamentally, our job is to build a distribution of risk. We provide information around that distribution and identify / *continued page 24*

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ensure the utility will be able to maintain its financial integrity and be able to earn a fair charge for its services. Amounts the utility collects through rates must be reported as taxable income. An insurance recovery would just reduce the utility's basis in the abandoned plant.

The ruling is Private Letter Ruling 201910001.

DATA POINTS. Strong growth in natural gas production in the United States will keep downward pressure on natural prices in 2019 and 2020, according to the latest short-term energy outlook that the US Energy Information Administration released in early June. Spot prices at Henry Hub were $2.64 an mmBtu in May. Low gas prices will cause the share of US electricity generated from gas to increase from 35% in 2018 to 38% in 2020, the agency said . . . . Coal will drop from 27% in 2018 to 23% in 2020. Nuclear will also fall to 19% . . . . Wind, solar and other non-hydroelectric renewables will move from 10% of US electricity generation in 2018 to 13% in 2020 . . . . Seventeen community choice aggregators in California — county-level organizations that buy electricity to supply to local residents — bought electricity in Q1 2019 from 28 suppliers. The largest single supplier, accounting for 20.6% of Q1 2019 sales, was Exelon Generation, the unregulated arm of a utility holding company based in Chicago.

— contributed by Keith Martin in Washington

Covariance Risk

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sources of uncertainty and insurers like Allianz and Nephila use that information to offer and price products.

On average, the market has underestimated covariance risk in bank hedges and, in particular, in the Texas market. Utilities have taken this risk historically under long-term contracts where they commit to take whatever electricity is generated.

The covariance issue is weather-driven. High heat or extreme cold during low weather events is what causes significant changes in the as-generated versus fixed quantities of power. The year 2018 saw some unusually cold temperatures in January and some unusually high ones in July. This led to a significant amount of dislocation, and the market woke up to the exposures that projects are bearing.

Now we are in 2019, and we see pretty diverging views across the market about what happened last year and how it might change. If we re-live a 2011 heat wave with the current generation supply stack, nobody knows how that will play out, but it is clear that it would be a significantly bad event for almost any wind project with a standard fixed-quantity hedge.

Solar v. Wind

Solar developers should think about covariance risk the same way as wind developers.

A lot of solar is being built in Texas, in part because power prices are high in the summer when wind speeds are low, so there is an attractive pricing dynamic for a solar operator. At the same time, the whole solar industry is aware of what happened in California with the duck curve. More solar electricity is generated during the middle the day than the grid requires. If the grid sheds the excess electricity, it can depress power prices in the same way that happens during an especially windy hour in the winter in Texas.

The prevailing view currently is that the extremely rapid growth of wind in Texas compared to solar creates a great opportunity, but the solar industry in Texas has the potential to become a victim of its own success. The question is where is the equilibrium reached, and how big of a role storage will play.

The focus on Texas has been driven by the fact that most of the financial hedging for wind projects to date has been in ERCOT. However, interest in hedges is expanding into other regions like SPP and MISO where the same relationship can be seen between wind speeds and power prices. There is less wind in PJM, so there is less of the causal issue of high wind speeds pushing down power prices, but there is still the same general correlation of lower prices during high wind periods. The severity of the issue varies from one market to the next, but it affects every power plant whose output is intermittent.

The longest balance of hedge being offered today is 10 years. Pricing gets more expensive the longer the term in some markets, but not in all markets.

The concern about price spikes during low wind events in the summer is most acute for the next three to four years in Texas. That is partly due to a belief that solar capacity additions will help to moderate price spikes during the summer months when extreme covariance risk is most acute.

Corporate Buyers

The issue of covariance is not unique to the seller of electricity. If a project enters into an as-generated power purchase agreement with a corporate buyer, it will have transferred the covariance risk away from the project and to the buyer of electricity.

Microsoft has been the most active in thinking about and managing this risk, and it was the first to embrace a solution through use of a "volume firming agreement."

A "volume firming agreement" works in much of the same way as a balance of hedge: it locks in a fixed value to the sum of the hourly short and long positions held by a corporate buyer who is meeting a fixed-shape load with an as-generated PPA.

Suppose a data center requires 50 megawatts of power every hour to run its operations. If it has signed an as-generated PPA with a wind farm to manage the risks of its electricity costs, how well that PPA performs as a hedge on energy costs depends on the correlation between the wind project's output and power prices. For example, if the wind dies and power prices spike and the data center still must buy 50 megawatts of power each hour, the data center is buying very expensive power despite the fact that it signed a PPA to mitigate energy price risk.

Microsoft decided it would like to shed that risk to an insurer in the same way that a project does.

Usually, the underlying PPA has already been signed and the volume firming agreement is added after the fact as a way to convert the PPA into something that is significantly more effective in managing the energy costs of a corporate buyer.

However, we are starting to see more corporate offtakers look at putting a volume firming agreement in place at the same time the PPA is signed. That gives them certainty about how their PPAs will perform as expected from the start.

In some cases, the project selling power under the PPA may or may not be aware of the volume firming agreement as the corporate buyer has a view that it should be free to manage its risk however it chooses without having to involve the project. In other cases, it becomes a three-party discussion among the project, the corporate buyer and the insurer. In either case, the PPA and the volume firming agreement are separate contracts.

Overall, projects and their investors should expect offtake arrangements to be much more dynamic in the future. Whereas traditional 20+-year busbar PPAs managed nearly all of a project's risks for a long period, today offtake contracts are typically shorter term and have various flavors of risk management. ◎

How Storage Will Grow

Energy storage is a solution to a range of problems. Different "use cases" are getting traction. Storage has not yet reached a tipping point in the United States, but adoption is accelerating. A panel of storage industry experts talked at Infocast Storage Week in San Francisco about the opportunities in the evolving US market. The following is an edited transcript.

The panelists are John Zahurancik, chief operating officer of Fluence, a joint venture between AES Storage and Siemens, Randolph Mann, president of esVolta, a utility-scale energy storage developer, Holly Christie, assistant general counsel of Invenergy, a large utility-scale project developer, and Brian Knowles, director of energy storage business development for Cypress Creek Renewables, a solar company. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Traction

MR. MARTIN: A solar CEO told us recently that storage is getting traction mainly in markets where people don't do math. It is getting traction in the rooftop solar market, but not as much elsewhere. Do you agree?

MR. MANN: No. The utility-scale projects that we are doing are economic for our utility customers, and that's why they are signing contracts with us.

MR. ZAHURANCIK: I think there is a new math. For a long time in the solar development field, the math moved in one direction: every year, a megawatt hour of electricity has had to get cheaper. Now we are finding some people are focused on value. It is not just about lowering the cost of energy, but it is also about supplying a range of new services that become possible with a combination of solar and storage. When you put those two things together, the project costs more, but it provides greater value to customers.

MR. MARTIN: The longer the sales pitch, the harder it is to sell. If you are trying to sell people on the additional value, I imagine it takes time to get traction.

MR. ZAHARUNCIK: It is definitely easier to say my megawatt hour costs less than your megawatt hour yesterday. I think people are starting to realize that it matters what time of day the megawatt hours are delivered. If I can't do anything other than pile megawatt hours on top of each other at the same time of day and in the same basic sunny locations, then I have a problem. I need to move them to the places where people actually have load, and I need to supply them at times of the day when people want to consume power. That is the challenge that we can solve with storage.

MR. MARTIN: At the annual ACORE/Euromoney Renewable Energy Finance Forum in New York a number of years ago, a panel of wind and solar CEOs talked about the addressable storage market. There was an opportunity at the time to build standalone storage facilities in PJM, but it seemed like there was a need for only a handful of such storage facilities. The addressable market seemed small. Has something changed in the last five years to make the addressable market much larger? If so, what is it?

MR. ZAHARUNCIK: The price of storage has fallen dramatically in that last five years to a point where we are starting to use storage to do capacity and energy jobs. Five years ago, it was used primarily for frequency regulation and ancillary services.

I started in storage in 2007. We viewed ancillary services and frequency regulation as a beachhead for getting into the broader market. It was a place where we could prove the technical capability of storage in a very challenging job that requires a speedy response. As the cost of storage has fallen, now storage can compete on price for a lot of other jobs. We are seeing people use storage instead of gas-peaking facilities in places where it is difficult to get permits to build new gas peakers. We are seeing solar combined with storage where the solar part brings the energy generation and the storage brings the firming and flexible capacity. The core economics have gotten better over time as storage has matured, and more people are assigning value to the flexibility it provides.

MR. MARTIN: Storage may already have reached a tipping point in places like California, where the grid must keep the electricity price high to keep gas peakers / continued page 26

Storage

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interested for the few hours a day when they are on call. Batteries have been able to come in and steal the lunch of the gas peakers.

MR. KNOWLES: People are starting to look at storage as a viable solution for a lot of traditional problems. For example, National Grid decided to put 48 MWh of batteries on Nantucket rather than build a third underwater transmission line to the island. Storage is a better way to serve the summertime peaking capacity.

MR. MARTIN: But these are all niche applications.

MR. KNOWLES: There are Nantuckets all over the grid. There are widespread congestion issues. I don't think we will rebuild the grid like we did in the beginning of the last century. It is hard to see the same level of investment in things like transmission infrastructure going forward, so I think we are starting to see asset managers and utilities think about storage as an alternative.

MR. MARTIN: So storage companies should look for places where the grid is congested. That is your best opportunity?

MR. MANN: We start with the niches and the beachheads, but as the cost of storage continues to decline and as the different potential use cases are recognized and valued by utilities, storage will become a very big market.

There are something like 100,000 megawatts of gas peakers in the United States. Storage can do a lot of those jobs. As wind and solar penetration increase, storage will be essential for shifting electricity to the time of day when there is the most demand for it.

MR. MARTIN: Is there a tipping point where renewables are X% of the local power supply when storage becomes essential?

MR. MANN: I don't know the answer, but we see utilities are valuing storage as peaking capacity that is fast ramping and that enables them to integrate more renewables into the grid.

Standalone Storage

MR. MARTIN: The conference program says this panel is about standalone storage, which obviously includes large standalone batteries. What else falls under the heading standalone storage?

MR. MANN: Right now, it is lithium-ion battery storage, because that is what is scalable, it is commercially proven, it is bankable, it is financeable, it is developable. We are technology-agnostic to the extent that other technologies can displace lithium-ion, but for now, we are pretty busy developing lithium-ion battery projects.

MS. CHRISTIE: We are doing a number of projects that we call standalone or that we pitch as standalone when we look for interconnection. But they are paired with solar or other assets, so standalone storage is not like that lonely guy who never gets chosen on the dating app. There is no lonely standalone storage.

MR. ZAHURANCIK: I don't know that I would go quite that far. We are building a 100-megawatt facility in California that is contracted as a standalone asset. It is under a PPA. We are in a partnership to build another 100-megawatt facility for Arizona Public Service. It is a standalone capacity and energy management facility. We have built similar facilities in the past for San Diego Gas & Electric. We have built them in Australia, Germany and the United Kingdom.

These are all facilities that are not intrinsically tied to any other power generating unit. They function as standalone resources. They register with the grid. They are managed as independent power resources. This year, we have seen more solicitations for large-scale standalone energy storage systems than we have ever seen in the past.

Storage has not yet reached a tipping point in the United States, but adoption is accelerating.

MR. MARTIN: Let's put this into perspective. How much standalone capacity is there currently in the US? How much more is under development or construction?

MR. KNOWLES: We are close to 1,000 megawatts of operating assets. Things have changed a lot over the period it took to get to this level. PJM kicked everything off in 2012 with a Reg D market. Nearly half of the installed capacity today is really serving that market. Those are short-duration, 30-minute or one-hour batteries.

MR. MARTIN: There are 1,000 megawatts, with 500 of those in PJM. Any idea of how much is under development or construction?

MR. KNOWLES: Every day, a new biggest project is announced that would double, triple or quadruple the existing installed capacity. We saw more than 1,000 megawatts contract two years ago. Last year, I think we saw about 1,500 megawatts of new contracts or transactions around the world. A good part of that is in the United States. The US has been the biggest market.

We are in that phase of storage where it is starting to pick up speed. I am in my second decade in this industry. We saw mainly niche applications over the last decade. Now we are starting to see larger players do their second, third or fourth large system and opportunities opening up in more countries around the world.

MR. MARTIN: Some in the audience may be here because they are looking for another career path. Looking at you, John Zahurancik, it must be an easy career path. You have no gray hair. [Laughter]

MR. ZAHURANCIK: It's all in my beard.

MR. MARTIN: Any idea what the breakdown is between independent ownership and utility ownership of the 1,000 megawatts?

MR. ZAHURANCIK: Historically, it was independently owned, but the new projects are increasingly utility owned. In the last few years, the utilities have started to look at storage as a rate-based asset. In some cases, they are doing it for transmission and distribution purposes, so it is like a traditional rate-based asset. In other case, they may be doing it through a deregulated part of the business. We continue to see large solicitations for independents.

Vistra is a good example, out with a 300-megawatt project that it is looking to build. Some large systems are a mix of utility-owned and independent-owned. It depends on the regulatory regime in each state.

MR. MARTIN: So it varies by state.

MR. ZAHURANCIK: We probably saw a couple dozen RFPs last year from utilities, and at least 75% of them were looking for PPA-type projects instead of rate-based projects. As an independent, we can bring some advantages to the utility in terms of nonrecourse financing and in terms of absorbing some technology, development, construction and maintenance risks. We can also sell the utility the particular product it wants, which in some cases might just be capacity, and then monetize the rest of the value of the asset on our own. I think utilities in organized markets will eventually gravitate toward that type of model.

Regulatory Drivers

MR. MARTIN: But the model does not help the utility grow. It grows by putting things in its rate base.

Switching gears, Randy Mann, what are the most important federal and state regulatory policies that are driving the storage market? Let's start with the most important.

MR. MANN: I think FERC order 841 is the most important in terms of opening access to new markets. At the state level, the inclusion of storage in integrated-resource plans that various states are adopting is helping utilities be more thoughtful about what can they can do with batteries and how to think about solicitations for batteries.

MR. MARTIN: That's two. Anybody want to add to the list?

MR. KNOWLES: The California mandate and the expected New York mandate are big drivers. Moving the renewable portfolio target in Hawaii to 100% is big.

MR. ZAHURANCIK: Add federal environmental standards that are forcing closure of old existing capacity. As utilities look at retiring older power plants that sit in places where it is hard to build new capacity, they still have to meet reliability concerns. There is an opportunity for storage to replace existing generating capacity.

MR. MARTIN: Does the federal government have the right policies in place at this point?

MS. CHRISTIE: The current federal government does not have anything in the right in place. [Laughter]. But we are moving in the right direction. The government is starting to think about how the grid should look in the future and what we need to do to access the whole grid as an entire unit.

MR. MARTIN: What does that mean, "access the whole grid as an entire unit"?

MS. CHRISTIE: I mean thinking about it in terms of we have a certain amount of asset here and a certain need way over there. When I have a whole lot of alcohol in my house, but I'm alone and there is a party down the street, I have to bring the alcohol to the party or the party will not be a lot of fun. [Laughter] [Applause]

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MR. KNOWLES: Or the party to your house. [Laughter]

MS. CHRISTIE: Or the party to my house. One or the other. Exactly!

MR. MARTIN: Anybody else want to comment on federal policies? What is missing at the moment? Is it what Holly said, "The alcohol is in the wrong place"? [Laughter]

MR. ZAHURANCIK: At the moment, storage qualifies for a federal tax credit only if it is paired with a renewable generating facility, in most cases solar. If storage qualified on its own, that would move the industry forward more quickly.

We talk to grid operators and utilities who say they would like ideally to put a storage asset smack-dab in the middle of a city area, but they can't build a wind farm or a solar facility there, so the storage asset ends up being paired with a wind or solar facility in a rural area. There is still a benefit, but the utility would get more locational advantages if it could put storage closer to the load. The tax credit forces less-than-optimal siting.

MR. MARTIN: The story so far is storage is getting traction, and not just in markets where people do not do math. If this is true, then why do we need a tax credit? Is it only getting traction when paired with solar projects?

MS. CHRISTIE: I started in the oil-and-gas sector, and that sector still receives a tremendous amount of tax incentives and credits. If my brother gets a pony, I should get a pony, too, especially since he's the lower-achiever of the family. [Laughter]

Storage is a new and developing industry. There are a lot of hurdles still to overcome. As the technology continues to develop and we continue to look at issues around decommissioning risks and things like that, it helps to have a tax credit to push the industry to a point where it can reach scale. Scale brings down costs.

MR. MARTIN: How important is the fact that a tax credit can be claimed currently by pairing storage with solar? Is most of the standalone storage paired with solar to qualify for the tax credit? Randy Mann, you are shaking your head, "No."

MR. MANN: We have nine projects under PPAs. None of them is paired with solar or wind. They are all what I would call truly standalone storage, front-of-meter and utility facing. That is the most efficient way to build storage because two assets do not have to be tied together. Storage can provide a service to the grid where it is most needed.

My vote would be to levelize the playing field. I don't think that adding a new tax credit for storage is the way to go. Let the market evolve. Costs are coming down quickly. The banks are interested in financing storage. The ability of utilities to rely on the capacity coming from storage is improving quickly.

Revenue Streams

MR. MARTIN: Let's shift gears and drill down into economics. Where standalone storage is privately owned, what are the current revenue streams? There is a capacity payment. There is an energy payment. What else?

MR. MANN: Our projects usually have a utility PPA. In some instances, it is a full-tolling PPA where the utility pays for capacity and also pays a variable usage charge. It also pays for electricity, which is effectively the cost of the fuel, much like in a gas-tolling agreement.

But the more typical PPA that we have — the more common structure — is an RA-type PPA where we are paid only for the capacity we provide the utility.

MR. MARTIN: What does "RA" stand for?

MR. MANN: "Resource adequacy." You could think of it as capacity. The battery is also dispatched into the ISO for ancillary services, for energy payments, to the extent we can optimize the use of the battery.

MR. MARTIN: So you have up to three revenue streams: a capacity payment, an energy payment and an ancillary-services payment.

MR. MANN: Correct.

MR. MARTIN: Does anybody see any other revenue streams in the market currently for privately-owned storage facilities? [Pause] None?

Randy, what is the breakdown, by percentage, of the three current revenue streams?

MR. MANN: It depends. The way we think about this is what capacity payment do we need to make our numbers work. Capacity payments are the easiest part of the potential revenue stream to finance. We try to make that number big enough that we are comfortable with the returns on the overall project given the variability of the other revenues.

MR. MARTIN: What are we talking about: 30% of the total revenue, 40%, 20%? Too hard to say?

MR. MANN: It is really hard to say, but it is a function of how are you bid for the capacity PPA.

MR. ZAHURANCIK: It varies by local market circumstances. We built a few systems in Australia recently where there is a very high premium on energy and ancillary services. Capacity payments in such a market are a relatively low percentage of total

About half the standalone storage capacity in the US today is serving the short-duration market in PJM.

payments. In other markets, we find it harder to monetize the non-fixed revenue streams so we look for a higher fixed payment to get over an investment hurdle.

MR. MARTIN: Randy, do you have a number for me?

MR. MANN: No. [Laughter]

What John just said is right. There are so many different value streams coming from the storage asset. A lot of those value streams depend on how you dispatch the storage asset and trade the services in the market. If you are going into the storage business thinking, "I can only do this if I have fully contracted revenues," it is probably not the right business, because you are going to reduce the value of your assets. You need to be able to participate in the market as broadly as possible.

MR. MARTIN: You have two operating projects. Were they both paid for entirely with equity?

MR. MANN: No.

MR. MARTIN: What revenue will the banks give you credit for in deciding how much to lend?

MR. MANN: Clearly the capacity piece of revenues is much easier to finance, but we have been able to finance a portion of the variable revenues. Obviously, the percentage of required equity is high in a new market. That may change over time as banks get more and more comfortable with the market participation of these assets.

MR. ZAHURANCIK: The tenor of the debt also makes a difference. In the UK market, banks have been willing to finance 50% of the project cost, but with five- to seven-year tenors.

MR. MARTIN: With cash sweeps.

MR. ZAHURANCIK: The banks have some visibility into the revenue streams for the next few years, but it gets more opaque after that, as they know the technology will continue to improve and new entrants will have an effect on prices. There is a fair amount of change going on now, and not necessarily around the asset as much as around the possible use cases and revenue streams.

MR. MARTIN: That's a good bridge. Randy Mann said there are three main revenue streams: capacity payments, energy payments and ancillary-services payments. Are there other revenue streams in other countries that are not yet present here and, if so, what?

MR. ZAHURANCIK: In the UK, there are locational transmission and distribution tariffs. Generators may have to pay a fee because they are putting power onto the grid at a time when, and in a place where, it is disadvantageous to the overall stability of the transmission system. If you can put storage in a place where the grid needs the power, then some of that revenue will come to the storage owner. That's an example of another stream.

MR. KNOWLES: We are starting to see a similar pricing scheme come to the US. That is part of the New York REV process: the value of distributed energy resources tariff has a locational benefits component to it, which looks at adjusting the capacity value of an asset based on where it is located. That should drive quite a bit of storage in New York.

MS. CHRISTIE: In some of our projects in Japan, we see a value-add from tacking storage to an asset. The interconnection costs will come down.

Financing

MR. MARTIN: I am interested in the elevator pitch that Randy Mann uses to persuade banks to lend. When you are financing a merchant wind or gas project, the project is pretty much assured of being dispatched by the grid. It is just a question of price, and you can put a floor under the price through a hedge. How do you get a bank to lend where there is no hedge and there is no certainty of being dispatched?

MR. ZAHURANCIK: It is a good question. I think that uncontracted revenues from a storage asset are easier to understand and price than from a power plant. The / continued page 30

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price of our fuel is equal to the price of our product — give or take a little bit — so I think it is a situation where we really can act as a price taker in the market and be assured of dispatch most of the time. Then it is a question of market prices.

MR. MARTIN: Banks are interested in branching out and doing new things. What percentage of the capital stack is debt where you can find it? John Zahurancik, you mentioned 50% in the UK under a seven-year mini-perm structure. What about in the US?

MR. ZAHURANCIK: It feels like 60% loan-to-value is where we start to feel resistance.

MR. MARTIN: That level of debt suggests a high overall cost of capital, because you have to use a lot of equity. Is the current cost of capital a significant impediment for storage companies?

MR. MANN: When you are building a utility-scale independent power business, cost is what counts. That is cost of capital, cost of equipment, and cost of balance-of-plant construction. We are seeing improvements in all of those areas. The cost of capital will improve as the market matures. We are seeing banks becoming much more comfortable with lending to storage from a technical perspective, from a market perspective and from a contract perspective. We will start to see the cost-to-capital come down for sure.

Interconnection

MR. MARTIN: Let me shift gears again. When you connect an independent power project to the grid, the grid does a study, and it may require you to pay for network upgrades to accommodate the additional electricity. When you connect a utility standalone storage facility, are there network upgrades? Are you helping relieve congestion? Do you get money back? What happens?

MR. KNOWLES: You don't get money back. [Laughter] That is a truism. [Laughter]

It is a really good point, actually. We found in some of the projects that we worked on with partners that the project did not get money back, but it avoided upgrade charges or it helped mitigate charges that the network was facing overall.

We do find, though, that because storage is pretty flexible in its footprint, you can generally find a location where you do not have to make network upgrade payments. For example, if storage is put where older power plants are retiring, the grid was already built around the idea of having a resource there, and it usually already has the existing infrastructure to accommodate a large-scale storage project.

MR. MARTIN: Any independent generator would have been in the same position.

MR. KNOWLES: Not in practice because the reality often is you cannot get a permit to build a new power plant or to repower the existing power plant.

MR. MARTIN: What happens when storage does not replace an existing power plant? Are you charged for network upgrades?

MR. KNOWLES: That's a good question. In every case where we would have had to pay for network upgrades, we just went to a different site. The siting flexibility was enough that you could find an alternate location that did not have those costs, if they were more than nominal in amount. You obviously have to pay to connect. There is some physical infrastructure that must be built. But if you are talking about upgrading huge pieces of a line or big central-system costs, generally another location can be found that does not require payment of such costs.

Data Points

MR. MARTIN: How long does it take a build a standalone storage facility? I am looking for data points. For example, wind projects on land take six to eight months of actual construction time.

MS. CHRISTIE: How much do you want to pay us? [Laughter] We can build it that fast. [Laughter]

We have done smaller projects in just a matter of a month or two. The issue is getting the equipment to a site. Larger projects, of course, are going to take more time. Most of the equipment is coming from Asia.

MR. ZAHURANCIK: Six to eight months is a typical timeline for a large-scale project. Often it is the transmission or the interconnection that is the gating item on the timeline.

MR. MARTIN: What is the cost per installed megawatt?

MR. ZAHURANCIK: It depends on how big the project is and how many hours of duration of storage capacity it will have.

For a project above 20 megawatts in capacity and an hour in duration, we are probably talking in the range, fully installed, of $600 a kilowatt, something in that ballpark. For a four-hour system, depending on the year the installation will occur, we are probably in the $1100 to $1200 a kilowatt range. Those numbers will vary depending on site conditions, what the project will connect to, and what it actually has to do.

MR. MARTIN: If you view yourself as competing with generators, you should be able to compete easily at those numbers in the current market.

MR. ZAHURANCIK: That is why I am still in it in the second decade. [Laughter]

Best US State

MR. MARTIN: Are there any questions from the audience?

MR. SANKARAN: Ravi Sankaran with Romeo Power. We are a battery technology company. Demand for storage is growing fastest in regions with robust incentives: for example, California and New York. This is the same thing we saw with solar. How far away are we to having more widespread adoption without such aggressive incentives? How far away are we to having more growth in the heartland and rust-belt states where there are no incentives?

Utility-scale batteries with four-hour storage cost $1.1 to $1.2 million an installed megawatt.

MR. MANN: At least half of the RFPs we saw last year were in places where there was no mandate. The utilities putting out the RFPs were usually looking for all-source peaking capacity, in which case storage is competing against gas and other forms of generation and, in many cases, competing effectively as John's numbers would indicate. So I think we are pretty close to there, if you value it properly.

MR. MARTIN: Regulatory policies tend to drive whether storage will be owned by utilities or be independently owned. Which state has the best business model?

MS. CHRISTIE: California. It is a state that has long looked at renewables and is doing what is needed to jump-start these businesses.

MR. KNOWLES: The big criticism about California is that the resource adequacy process is not transparent, and so you do not necessarily know at what price utilities are procuring their resource adequacy. New York would say what it is trying to do with the REV process and VDER tariffs is to more closely associate locational value and environmental value with each type of asset being deployed.

MR. MARTIN: So you like the New York approach.

MR. KNOWLES: It is super complex, for sure, perhaps even overly complex, but it is thoughtful. New York is really trying to get it right.

MR. ZAHURANCIK: I would just say about New York that Audrey Zibelman has done more in Australia in a short time as head of the grid operator than she was able to do in all of her years as head of the New York Public Service Commission. New York is incredibly complicated and its approach has not led to a lot of actual installations. The state that I think is doing a lot right is Arizona.

MR. MARTIN: What is it doing right that others are not?

MR. ZAHURANCIK: The major Arizona utilities are all in the process of procuring storage for various needs. The Arizona Corporation Commission has done a good job of forcing the utilities to look at all the alternatives and really consider what's the best option today rather than what might have been the best option historically. Some very large projects have been put out for bid. All of the utilities are pursuing storage in one way or another. They are pursuing it for generation alternatives and also within the network. They are doing it on the basis of economic merit.

Opportunities

MR. MARTIN: One of the issues in the market is where will storage land? Is it a transmission asset so that it best resides with the grid? Is it best behind the meter? Advanced MicroGrid Systems in California put a lot of storage facilities at florist shops, grocery stores and other commercial sites, and then offered the storage capacity to Southern California Edison. At the same time it earns other revenue from managing energy usage for the commercial hosts. What do you think is the long-term viability of that model versus the type of projects you are pursuing? Randy Mann.

MR. MANN: Both models work. There will continue to be a behind-the-meter storage market as energy users look to reduce their energy costs, but storage also fits / continued page 32

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on the utility transmission system, it fits on the utility distribution system, and it fits in the utility generation stack as well. If I had to say where we see the biggest opportunity for growth, it is in providing peaking capacity for utilities.

MR. MARTIN: It is stealing the lunches of the gas-fired generators.

MR. MANN: Providing a slightly different product and hopefully at a cheaper price, which is particularly valuable in a place like Arizona or California where there is a ton of midday solar electricity that does not fit the shape of the system load. Storage may be the right asset.

MR. MARTIN: So displacing peakers, dealing with the duck curve in California. Another opportunity is to use storage to address congestion on the grid. Are there other opportunities besides these two?

Banks financing storage projects start to push back when the debt reaches a loan-to-value ratio of 60%.

MR. ZAHURANCIK: The other one is commercial entities that are taking a stronger role in procuring or managing energy for themselves are also starting to look at storage as part of that mix.

Commercial customers are driving the PPA market for renewables to a large degree today. They are now starting to look at adding storage as a way to balance the renewable electricity they have procured and better manage it, or at using storage to reduce demand charges or to protect factories from interruptions in the electricity supply. They are building it into the whole system. It is a version of a microgrid.

MR. MARTIN: We heard from Randy Mann that a basic business model is the storage owner has a PPA, and it earns three revenue streams: capacity payments, energy payments and payments for ancillary services. How do you see the business model changing over time?

MR. ZAHURANCIK: In California, you have a resource adequacy contract with the utility and then access to wholesale markets. I think that can be replicated in other markets.

In PJM, there is talk about reforming the capacity market and thinking about a fixed resource requirement, which would essentially mimic the California resource adequacy process. There again you could have a market with a direct contract with a utility like Dominion, but if the storage asset is not being called on by the utility, it can participate in the PJM frequency or capacity market.

The hybrid structure is important. The markets in which you are participating differ from one place to the next. Maybe in the northeast it is a regulation and capacity market, and in California it is a day-ahead versus real-time energy market.

MR. MANN: Where storage can access fairly and fully the wholesale markets, it allows for a lot more experimentation with different contract structures. The utility can buy what it really wants, and the market can buy the other pieces that it wants. This creates a more economic and valuable asset.

Audience Questions

MR. MARTIN: We are running short on time. Let's fit in a few more audience questions.

MR. ROUSSELLE: Adam Rousselle with Renewable Energy Aggregators. Why isn't pumped-storage hydro, which costs around $1,000 a kilowatt for 12-hour runtime, getting the same traction as lithium-ion batteries? Is it the lead time of three and half to four years to build? Is it customer preferences? What is the critical difference?

MR. ZAHURANCIK: That's a great question. I think where you can do pumped storage, it is a great solution. Where people have built those facilities, they are tremendously valuable. They run and support the markets that they are in very well. The biggest issue I see is that you have to find the right conditions to make them work.

MR. MARTIN: You have to have water . . . .

MR. ZAHURANCIK: . . . and you have to have a geographic condition that allows you to pump like that. The environmental permitting is difficult. If you don't naturally have the required terrain and you try to modify it in some way, you run into a series of other environmental permitting issues. These facilities also tend to be distant from the customer load.

Those are the limitations I see. I don't have anything against pumped storage and think we should build as many such facilities as we can do economically. For places where we need something in a load center or we need something more modular and lack the required geographic conditions, battery storage is a very flexible alternative.

MR. WIENER: Jeff Wiener with Eos Energy Storage. I heard your comments about lithium-ion, and I understand that it is financeable and easy to install, but how easy will it be for another technology to break into the market, and what are the critical factors that you would look for in an alternative technology?

MR. KNOWLES: It is tough actually. If you are trying to sell to utilities or project developers, it is a very tough market because we are dealing with critical infrastructure, and it needs to work at a very high level of reliability and predictability. That usually means the technology must have a track record at commercial scale.

Batteries have taken a long time to get there. We are only just now seeing an acceleration.

The other challenge of dealing with utilities is each has its own service territory and lots of stakeholders. Instead of selling once as an economic solution, you really have to convince engineers and every utility as you go along that this is something that will add to, or at least not take away from, the reliability of their systems. There are a lot of barriers. That said, good ideas that address real problems eventually get traction.

MR. ERICKSON: Dave Erickson with New Hampshire Electric Cooperative. Realistically, do you see any competitor to lithium-ion in the next five years, and what might that be?

MR. MARTIN: Flow batteries in China?

MR. ZAHURANCIK: You have to take the data from China with a lot of grains of salt.

We have a proven technology today in lithium-ion that is built at volume with deep-pocket balance sheets behind the core technology. It is financeable. Those are advantages that other technologies then have to overcome or at least match to come into the space. Within a five-year time period, I don't think there is much. As you start to move beyond that, there will be variants of lithium and other improvements. A lot of people are working on improvements to electrolyte, anode-to-cathode material, just to get away from cobalt, if nothing else, that I think we will see in that window. But I don't know that we will see a wholly new proven solution within that time frame.

MR. ERICKSON: LFP?

MR. ZAHURANCIK: Lithium-ion-phosphate batteries are a variant of lithium. We have done a lot projects with LFP. The biggest problem sometimes is cost and size. They have a different footprint.

MR. HSIEH: Nathan Hseih with The Mobility House. How do you set your expectations for performance of these assets?

MR. KNOWLES: They do need to work, for sure. The expectation is that there will be similar performance in line with what you would expect from a solar project. Obviously, as a newer technology, there will be things that go wrong. That is what differentiates the good suppliers. They are willing to put a balance sheet behind a guarantee that the projects work. As John suggested, you can find lots of things in China right now — really cheap batteries — but it is really important to find an integrator that will warrant the batteries, warrant the inverters and warrant that they all will work together.

MR. BRYAN: John Bryan, EPC Power. What are your greatest supply-chain risks at this point?

MS. CHRISTIE: Trying to get very large amounts of battery cells from Asia. Often, especially for our larger projects, we tend to buy individual components where we can find them, then package everything together and ta-da, there it is. It's a fruit basket. A fruit basket is not really a fruit basket unless you have bananas.

Wisdom

MR. MARTIN: Here is our exit question. Panelists, tell us one thing that you think most people new to storage don't know about it? You have been in this market for a while. What important lesson did it take time to learn?

MS. CHRISTIE: One huge challenge for me in contracting with utilities for these projects has been that there are no standard contract forms. A counterparty will often provide a form that has nothing to do with the technology. "You can stick it into this purchase-of-a-bus contract, right?" It's like, "No."

There is a huge amount of risk around such an approach to contracts that people don't seem to understand. Storage projects go through several phases: development, procurement, construction, operation. You can't throw / continued page 34

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everything into the mix and hope it turns out right. Each phase must be considered on its own. This can be a struggle.

MR. MANN: I agree with that, but to me the biggest challenge is learning how to deal with market participation, managing assets day-to-day in the market, and also thinking about forecasting and projecting how those assets are going to look in the future.

MR. MARTIN: It is a very different market than what you are used to as a generator.

MR. MANN: It is much more complicated.

MR. KNOWLES: Definitely the complexity of building a storage project, whether it's a lithium-ion battery or a flow battery. The relationship between the power electronics and the storage medium is very complicated when building a fully integrated project. People tend to say it is a box with a refrigerator on it; it should be fine. There is a lot behind the scenes that goes into to building these projects.

MR. ZAHURANCIK: It is a complex system that you are building, and it needs to operate in a certain way over time. People that come, particularly out of the renewable energy field where we have had a long time to develop standards and interfaces and disaggregate the pieces have gotten comfortable with buying panels from him and inverters from her, and somebody does balance of plant, and everything works together. We have had 40 to 50 years to get this right.

When we put the fruit basket of energy storage together, the bananas and the apples don't like each other, and the grapes just get soggy, and none of it really works unless somebody is actually making it into a fruit salad instead of a fruit basket.

Making everything work together takes discipline, diligence and investigation. It is not plug and play, and it is certainly not plug and play into all of these different market structures and market rules automatically on day one. It takes hard work to shape the technology in a way that will make it a useful substitute for power plants that have historically served these markets.

Development Banks: Immunity from Lawsuits

by Jeremy Hushon, Rachel Rosenfeld and Jonathan Franklin, in Washington

A US Supreme Court decision has left room for debate about when development banks can be sued in US courts.

The court held in late February that the International Finance Corporation does not have absolute immunity from such lawsuits. In so doing, the court reversed decades of precedent and practice under which IFC had enjoyed such status.

The Supreme Court held that the International Organizations Immunities Act of 1945 (IOIA) affords international organizations, such as IFC, the same immunity from suit that foreign governments enjoy today under the Foreign Sovereign Immunities Act of 1976 (FSIA).

In other words, IFC enjoys immunity that is limited by various exceptions, such as engaging in commercial activities, as opposed to virtually absolute immunity it had when the IOIA was originally enacted.

The opinion included a number of stipulations noting how the ruling might not affect all international organizations equally. Furthermore, the FSIA will still afford IFC and other international organizations some degree of immunity protection.

The case is *Jam et al. v. International Finance Corp.*

IFC was one of several lenders that made loans of $450 million in 2008 to finance a coal-fired power plant in Gujarat, India.

A group of Indian fishermen supported by EarthRights International, a non-governmental public interest organization, sued IFC for damages and injunctive relief in federal district court in Washington, where IFC's headquarters are located. The suit alleges that IFC failed properly to enforce the covenants in its loan agreement and thus failed to prevent or stop the power plant from polluting its environs. Of note, the plaintiffs have elected, at least to date, only to sue IFC. They have not brought suit against the owner of the plant or any of the other lenders to the project.

IFC's initial defense was to claim absolute immunity from suit under the IOIA. Both the district court and a US appeals court where the decision was initially appealed applied longstanding precedent to dismiss the case, holding that IFC was entitled to the virtually absolute immunity accorded foreign governments

A US Supreme Court decision has left room for argument about when international development banks can be sued in the US courts.

when the IOIA was enacted. The fishermen appealed to the Supreme Court, arguing that the IFC was entitled under the IOIA only to the limited immunity that foreign governments currently enjoy, and they were backed by an amicus brief from the US government.

The Supreme Court reinstated the lawsuit and sent the case back to the district court for further proceedings.

Take-Away Points

The opinion points out that an international organization's charter may specify a higher level of immunity, citing the United Nations charter as an example, which specifies that the UN "shall enjoy immunity from every form of legal process except insofar as in any particular case it has expressly waived its immunity." The charter of the International Monetary Fund includes a similar statement of immunity. This type of specified immunity is not affected by this ruling. Notably, the IFC's articles (https://www.ifc.org/wps/wcm/connect/corp_ext_content/ifc_external_corporate_site/about+ifc_new/ifc+governance/articles/about+ifc+-+ifc+articles+of+agreement) do not include any statement of immunity from lawsuits.

While acknowledging that commercial activity is an exception to immunity under the FSIA, the opinion notes that "it is not clear that the lending activity of all development banks qualifies as commercial activity within the meaning of the FSIA." To be considered "commercial," an activity must be "the type" of activity "by which a private party engages in" trade or commerce. Thus, for example, a loan by the World Bank to a foreign government may not be considered commercial in nature.

In addition, the opinion says that "even if an international development bank's lending activity does qualify as commercial, that does not mean the organization is automatically subject to suit" as "the FSIA includes other requirements that must also be met." For example, for immunity to be abrogated under the commercial activity exception of the FSIA, the commercial activity must have a "sufficient nexus" to the United States, and the lawsuit must be "based upon" either the commercial activity itself or acts performed in connection with the commercial activity.

The opinion gives as an example a lawsuit brought based on tortious activity abroad as not "based upon" commercial activity within the meaning of the FSIA's commercial activity exception. Presumably a development bank would have immunity from that type of lawsuit. Importantly, the opinion notes that at oral argument, the US government "stated that it has 'serious doubts' as to whether petitioners' suit, which largely concerns allegedly tortious conduct in India, would satisfy the 'based upon' requirement."

This case is an example of a type of activist litigation that bears watching by the entire finance community. EarthRights says its goal is to defend human rights and the environment by publicizing and bringing legal actions against organizations it believes are perpetrating abuses. Its strategy is to change the habits of international lending institutions by holding them accountable, as opposed to following the most direct path to achieve restitution for the aggrieved farmers and fisherman by taking legal action against the owners of the plant. Based on press coverage and its statements about the recent Supreme Court ruling, EarthRights is also aiming for accountability through publicity, regardless of what the eventual outcome of the case may be.

With its immunity under the IOIA now qualified by the FSIA, IFC and other similarly situated international organizations are likely to see an increase in lawsuits filed against them. This will then lead to debate about the past FSIA case law and some notable differences in status of international organizations, as compared to foreign countries, and further exploration of the scope of international organizations' now more limited immunity from lawsuits in US courts. ◎

How To Plan Ahead for Back-Leverage

by Sue Wang, in Washington

Cash is king as developers race to start construction on US projects before wind and solar tax subsidies disappear. Back-levered debt is a reliable way of getting more cash into the hands of developers. Back-leverage rates are competitive, and some lenders are willing to give credit to merchant sales beyond the term of the initial power purchase agreement.

Back-levered debt sits upstream of both the project and any tax equity financing. There are three forms of tax equity financing. All wind projects and most solar projects are financed using a partnership-flip structure in which the developer and a tax equity investor own the project through a partnership.

The developer borrows against the monthly or quarterly cash distributions that the developer receives as its share of cash flow. The loan is secured by a pledge of the developer's interest in the tax equity partnership.

Back-leverage financing is sometimes closed before or simultaneously with the tax equity financing, but it is also flexible enough to be added at a later date. Unlike tax equity, back-leverage financing can be added to projects that started commercial operation years ago. This flexibility is one of the most appealing aspects of back-leverage financing.

To leave the door open for a future back-leverage financing, it is important to make sure that a tax equity deal does not contain any elements that would offend a back-leverage lender. The two sets of investors should be able to co-exist peacefully.

There are two fundamental questions that back-leverage lenders need to answer when they diligence the tax equity deal.

First, what issues could potentially stop the expected share of cash flow from reaching the developer? Next, if a cash-flow problem were to arise and the back-leverage lenders decided to exercise their enforcement rights, would there be any significant barriers to foreclosing on the collateral?

Engaging with these two concerns thoughtfully is critical at the outset. Doing so will enable future back-leverage lenders to come into a deal without disturbing the existing tax equity agreement. Nobody wants to re-open the tax equity deal for amendments and inter-creditor agreements, so pre-bake your tax equity deal with the things every back-leverage lender will need. A little bit of advance planning goes a long way.

Cash Flow and Cash Sweeps

Most term sheets include a tidy chart indicating how cash flow is split between developers and tax equity investors, and in most cases developers assume that cash will follow the chart. However, lenders and tax equity investors are always considering the downside scenario.

Tax equity investors dislike risk, and tax equity vehicles often include cash sweeps of 50% to 100% to cover any indemnities owed to the tax equity investor and, in some cases, to help the tax equity investor reach its target yield once the expected date for doing so has passed.

A cash sweep means that some portion of the cash that otherwise would have been distributed to the developer will instead go to the tax equity investor.

Two main issues should be negotiated with tax equity investors to leave room for back-levered debt.

To reduce the likelihood of a cash sweep, it is important to pay careful attention to the events that could trigger an indemnity obligation. Anything off-market would raise questions from back-leverage lenders. Some of the indemnification risk can be addressed by purchasing tax insurance when closing the tax equity financing. In addition to protecting the developer and tax equity investor, tax insurance coverage would also give comfort later to the back-leverage lenders that, if the tax character of the project is challenged, cash flow would only be temporarily diverted while the insurance claim is pending.

In cases where back-leverage and tax equity financing are being negotiated simultaneously, it is common for back-leverage lenders to ask that scheduled principal and interest payments of their loan be excluded from the cash sweep.

However, room can be reserved for back-leverage lenders even if there is limited visibility on a future back-leverage loan. As long as the maximum cash sweep is less than 100% of the developer's distributions, there will be some cash flow for the back-leverage lenders to lend against. A 50% cash sweep usually leaves enough room for back-leverage loans, but the actual sizing depends on the cash outlook of the specific project. It is rare to see a project that is able to support back-leverage loans if the cash sweep is above 75% of developer cash flow, unless scheduled principal and interest is excluded from the cash sweep.

Developer Collateral

Back-levered debt is secured by a pledge of the developer's interest in the tax equity partnership. This is called the class B pledge because most of the market has fallen into the practice of calling the tax equity investor the A partner and the developer the B partner. There is no significance to the order.

Without careful attention to drafting, restrictions in the tax partnership agreement can make it impossible to pledge the class B shares without consents and waivers. A specific carve-out is often required to allow the class B interest to be pledged as collateral to a lender. Without a specific carve-out, pledges of upstream interests may require consent from the tax equity investor, which can cause unnecessary costs and delay.

It is also critical that the partnership agreement allows enough room to maneuver for the lender to enforce the class B pledge. If the loan is in distress, the lender needs the ability to sell its collateral quickly, without getting consent of any kind from the tax equity investor. The sale could be an auction or a private sale, or the lender may foreclose and hold the interests itself for a time.

Many tax equity investors impose restrictions on changes of control because they want to make sure the developer stays with the project, but a carelessly drafted change-of-control provision can have an unintended consequence of closing the door on a future back-leverage financing.

When working out the details of a tax equity deal, an experienced negotiator should specify that the class B interest can be pledged in favor of a back-leverage lender, defined as a lender whose collateral package does not reach the project assets. Furthermore, foreclosure (and a transfer in lieu of foreclosure) by the lender should be specifically permitted without investor consent, as long as a specific list of conditions is met. A favorable set of papers would include a special exemption for the first entity to whom the lender transfers its interests.

In favorable conditions, the only restrictions upon a transfer by the lenders would be regulatory requirements and tax considerations. Any transfer that would cause the IRS to treat the company as a corporation, for example, would not be permitted. Likewise, any transfer that triggers recapture of tax credits claimed on the project is either flatly prohibited or can only done with an opinion from outside counsel that no recapture will occur or with an indemnity from the developer for the recapture liability.

Most lenders are not granted unfettered freedom to resell the class B interest to whomever they please. The developer, as the class B member of the tax equity partnership, has managerial responsibilities and indemnity obligations, and the tax equity investors need to be comfortable that any successor to the class B interests can perform both obligations. Tax equity investors do not want to find themselves in a partnership with a stranger.

One way to balance the competing priorities is to establish a set of objective criteria at the outset to define an acceptable transferee. Financially, the transferee is usually required to meet specific measures of financial strength and to deliver a parent guaranty to replace the parent guaranty of the outgoing class B member.

Operationally, the transferee must be capable to managing the project. Experienced negotiators will specify clear, objective criteria in advance so that potential transferees never need to be individually evaluated and approved. The criteria usually include a minimum quantity (in megawatts or in dollar value) of renewable power projects that the transferee has developed or operated, plus a minimum number of years of experience in the industry. Furthermore, the operational experience should always be able to be satisfied by entering into a professional service contract with an acceptable third-party manager.

Having clear, objective criteria in advance is the last piece of the puzzle that makes lenders feel */ continued page 38*

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comfortable that they will be able to foreclose on the class B interests without needing to go back to the tax equity investor for consent. The lender itself should not be required to satisfy these metrics to foreclose on the interest after a debt default.

Final Thoughts

A back-leverage lender will always diligence the tax equity documentation because the tax equity partnership sits between it and the cash flow. Tax equity investors do not generally object to having back-leverage lenders in the capital stack, but it is not their job to think about what such lenders will need.

It is the developer's job to manage the capital stack, and it is the developer's burden to ask for consents and amendments if the back-leverage lender is not satisfied with the existing agreement. This article has covered the key items that every back-leverage lender looks for, but there is one additional clause that smart developers always check: make sure the confidentiality provisions allow investors and potential investors to review the documents. ◎

US Solar Financing Update

Activity in the US solar market has picked up considerably as developers race toward a deadline at the end of 2019 to start construction of remaining projects to qualify for a 30% investment tax credit on new solar projects. More projects are seeking financing than in 2018. The race is on to start construction of as many projects as possible. Senior executives of four solar companies talked at the annual Solar Energy Industries Association finance workshop in New York this spring about the state of the market. The following is an edited transcript.

The panelists are Samir Verstyn, chief investment officer and chief operations officer of Origis Energy, Rob Martorano, chief investment officer of Greenskies Renewable Energy, Sripradha Ilango, chief financial officer of Soltage, and Vincent Plaxico, managing director for project finance at Recurrent Energy. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

New Trends

MR. MARTIN: What new trends are you seeing in how solar projects are financed?

MR. VERSTYN: One trend is that some tax equity investors are also providing the back-levered debt. This creates efficiencies and reduces the transaction costs. Tax equity is also playing a different role in the capital stack.

MR. MARTIN: Have you seen many tax equity investors also offer debt or is it still just a small subset of tax equity investors?

MR. VERSTYN: It is a small subset. We know a couple that are doing it, but more are looking into it. There are complications under Reg. W. The complications affect how such deals are structured.

MR. MARTIN: What advantage is there to the sponsor of shopping for debt and tax equity in the same place?

MR. VERSTYN: You have one counterparty in essence, although they are different affiliates.

MR. MARTIN: But two sets of lawyers.

MR. VERSTYN: They may be more willing to try to accommodate each other. It is a smoother process. There may be efficiencies with the number of insurance and other consultants that have to be brought into the deal. The downside is that Reg. W limitations cause your equity ticket to go up on the sponsor side.

MR. MARTIN: You said tax equity is playing a different role in the capital stack. What did you mean by that?

MR. VERSTYN: It is not so much a different role, but the reduction in the corporate tax rate to 21% means that the tax losses are worth less so the amount of cash the tax equity needs to stay at the same level of investment has gone up. That affects how we look at tax equity. It is an expensive source of capital. We take this into account when we analyze our optimal overall capital stack.

MR. MARTIN: Rob Martorano, what new trends do you see?

MR. MARTORANO: We are seeing more use of sale-leasebacks in the commercial and industrial and distributed solar markets. The tax equity investor in a sale-leaseback provides the entire capital stack.

MR. MARTIN: Are the lessors mainly regional banks?

MR. MARTORANO: Yes.

MR. MARTIN: Have you seen any large banks in the sale-leaseback market?

MR. MARTORANO: Occasionally, but they still need large volumes which is not always as easy for a C&I solar company to provide.

MR. MARTIN: The large banks tend not to like sale-leasebacks because the financing term is too long. They prefer shorter-term financings. Sponsors have tended not to like sale-leasebacks because they suspect the banks are not paying anything for the residual asset value. It galls sponsors to have to buy back the asset at the end of the lease term. How do you get past this issue as a sponsor?

MR. MARTORANO: Some lessors offer fixed-price purchase options. We factor that into the cost of the financing. We may also push for a shorter-term lease.

MR. MARTIN: Are banks doing sale-leasebacks claiming a 100% depreciation bonus?

MR. MARTORANO: Yes. That makes for better financing terms. Sale-leasebacks also tend to have lower transaction costs.

MR. MARTIN: Shrips Ilango, what new trends are you seeing?

MS. ILANGO: Our challenge has been how to finance large portfolios of small assets that are geographically dispersed. Before, we had to go to three different lenders for three different geographies. As the market has matured and as the banks have looked for repeat business, they have been able to get comfortable with different risk profiles. Doing a series of financings with the same parties helps make the transactions efficient and quick.

MR. MARTIN: Vince Plaxico, new trends.

MR. PLAXICO: I have three. There has been a fusion of corporate and project finance, which can help developers with earlier-stage capital. I will be a little bit vague there.

MR. MARTIN: I was going to ask what does that mean?

MR. PLAXICO: We will get to it. [Laughter]

Next, banks are more willing to lend against the merchant tail, or the projected revenue after a power contract ends. Finally, the spread on debt for projects with community choice aggregators as offtakers, especially in California, continues to improve.

MR. MARTIN: So what does "blend of corporate and project finance" mean?

MR. PLAXICO: As developers, we need different sources of capital, whether it is letter-of-credit facilities or just debt that is more development-stage and not based on projected cash / continued page 40

The typical solar capital stack is 30% to 40% tax equity, 30% back-levered debt and 30% true equity.

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flows. We are starting to see banks take a view that traditional project lending at rock bottom rates may not be the best use of their capital, so they may want earn a higher rate by lending during the development stage. These are commercial banks. I am not talking about hedge funds.

MR. MARTIN: How early in the development stage?

MR. PLAXICO: It varies but some projects might only have site control and interconnection agreements. Others might have power contracts, but still have development milestones ahead.

MR. MARTIN: What is the pricing on such development loans?

MR. PLAXICO: It depends what type of collateral you give the banks.

MR. MARTIN: I can see where this is headed. [Laughter] Let's go back to the full panel. In many conferences over the past few years, people have talked about a wall of money chasing projects. Do you feel like there is still a wall of money? Are people throwing money at you?

Wall of Money

MS. ILANGO: As a qualified statement, nobody has ever given me money for free. [Laughter] That said, there is a lot of capital interested in this space. We have seen returns tighten across the capital stack, even maybe for tax equity. There is a lot of capital chasing a limited number of projects, but it doesn't mean that deals are being done irrationally. Everyone has a return requirement that is based on his or her underwriting standards.

MR. PLAXICO: We sold about 700 megawatts of projects last year, and 60% of the projects we sold were to international investors. Interest from Asian and European investors remains high.

MR. MARTIN: Do you have a sense for what discount rates the winning bidders were using to price?

MR. PLAXICO: It depends on project characteristics. However, high-quality operating projects clear in the high 6% to 7% levered IRR range, assuming a 35- to 40-year useful life and taking the merchant curve from a third party without a major discount.

MR. VERSTYN: We also see a lot of European money coming in. We have an international business, so we see what is happening in countries like The Netherlands and Germany where levered yields on solar assets are around 4.5%, with the floodgates being potentially reopened by the European Central Bank. Falling interest rates in Europe bring more money to the US in search of higher returns.

MR. MARTIN: What return are developers getting on projects: single digits? If so, how do the private equity funds play in this sector?

MR. VERSTYN: Yes. It is single-digit leveraged returns.

MR. MARTIN: How do the hedge funds play in this sector? Maybe the answer is they don't. They usually look for returns in the mid- to high teens.

MS. ILANGO: They don't.

MR. PLAXICO: I agree.

MR. VERSTYN: It is not viable because you are bidding for PPAs in a very competitive market. If you start factoring in that cost of capital, you will not be able to win.

MR. MARTIN: Is there any part of your business for which there is a shortage of capital? Early-stage development? Late-stage development seems to be flush with money.

MR. MARTORANO: We are doing C&I and small ground-mounted distributed solar. There is no shortage of capital for any stage of our business. It is just a matter of the terms that come along with it.

New Financial Products

MR. MARTIN: What new financial products have investment bankers and others been pitching to you lately?

MR. MARTORANO: Mostly securitizations.

MR. MARTIN: So borrowing in the public debt market against customer revenue streams from C&I portfolios. It is a form of back-levered debt and probably a way to borrow at a lower rate than you can borrow from a bank. What rate are you seeing in that market?

MR. MARTORANO: We have not done it yet, but what has been talked about is in the 5% or sub-5% category.

MR. MARTIN: That doesn't seem to be much better than what the banks are offering.

MR. MARTORANO: It's really not, but the idea is to put the facility in place and save on future borrowings.

MS. ILANGO: There is also a benefit from aggregating portfolios. The effect is to start mimicking the rates on offer in the utility-scale solar market.

MR. MARTIN: So the next big thing for developers of smaller projects is aggregation to save on borrowing costs. Is there a next big thing for utility-scale solar that people are pitching?

MR. PLAXICO: We are getting pitched for sell-side M&A due to our business model. We are seeing inbound investor interest in projects that have exposure to PG&E. We are also being pitched on equipment loans to borrow and stockpile equipment that can be used as a basis for qualifying projects for the investment tax credit.

MR. MARTIN: Investors interested in projects with PG&E exposure are making a bet that the politicians will pull PG&E back from the brink?

Sudden changes in tariffs are making it a gamble to commit to sell electricity at fixed prices from projects under development.

MR. PLAXICO: They think there is an additional spread to be earned right now due to the uncertainty.

MR. MARTIN: Let's talk more about equipment loans. Solar companies are pressing against a deadline of the end of this year to start construction to get a 30% investment tax credit. One way to start construction is to stockpile equipment. Few companies have the money to stockpile lots of equipment. What equipment loan terms are you seeing on offer from bankers?

MR. PLAXICO: We are seeing a lot of interest from banks. The pricing is around LIBOR plus 3% in cases where there is a reasonable loan to value.

MR. MARTIN: What do such lenders take as collateral: just the equipment?

MR. PLAXICO: They will get a little bit more than that.

MR. MARTIN: Has anyone else seen banks pitch for equipment supply loans?

MR. VERSTYN: Not necessarily banks, but what we have seen is private money willing to lend based not so much on the spread, but with the intention to get their hands on the projects because they have long-term ownership aspirations.

Supply Constraints

MR. MARTIN: No matter how you start construction, whether you do it by physical work or stockpiling equipment, there will be supply constraints. There was a story in Recharge this afternoon about how wind developers are already running into difficulty getting cranes to put up turbines in ERCOT that have to be up by the end of 2020. Are you already running into supply constraints in the solar market as you start thinking about how to start construction by the end of 2019?

MS. ILANGO: We saw the same thing a couple years ago in Massachusetts when the SREC II program came to an end. EPC prices went up significantly. Panel prices went up significantly. We fully expect something similar to happen, and it will be a balancing act among EPC price, panel price, the investment tax credit stepdown, getting a lower price on everything and getting a 26% rather than 30% tax credit by waiting to start construction next year.

MR. MARTIN: You are all developers. What is your current thinking about whether it is better to start construction with physical work or by stockpiling equipment?

MS. ILANGO: I think there is a warehouse in New Jersey where you can still find section 1603 panels. [Laughter]

MR. VERSTYN: The lowest-cost option from a capital perspective is to start construction by getting work started on transformers. You need a dedicated project in order to do so because your transformer is customized.

The other side is that incurring at least 5% of the project cost by taking delivery of solar panels or other equipment provides greater certainty that you will be able to raise tax equity. We see scarcity and prices creeping up as a result of that. There are no shortages at this point in time, but things could start to change in the next couple months.

MR. MARTIN: Rob Martorano, physical work or 5% test?

MR. MARTORANO: We'll probably go */ continued page 42*

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with the 5% test. We probably have 100 to 150 projects at the end of the year that we will need to safe harbor. It is easier to rely on the 5% test.

MR. MARTIN: What equipment will you stockpile?

MR. MARTORANO: Panels.

MR. MARTIN: Are you worried about the efficiency of panels improving over time and making your stockpiled panels worth less?

MR. MARTORANO: Not overly concerned about that. It is a matter of price. If we can procure panels at the right price, then we eliminate a supply risk. We are already seeing shortages pop up in various sizes for projects that we plan this year.

MR. MARTIN: Vince Plaxico, what do you plan to do?

MR. PLAXICO: Some tax lawyers have said it will be easier for tax equity investors to get comfortable with the 5% test than physical work, so I think that is where we will end up. It might be modules, it might be other equipment.

MR. MARTIN: The solar panel tariff will drop to 20% next February and to 15% a year after that. I suppose you could hold equipment outside the country and bring it in later when the tariff has eased a bit.

Let's switch gears and talk about electricity prices. They have been falling and so there is less cash in deals. How is that complicating financing?

Changing Capital Stacks

MR. VERSTYN: It depends on what part of the capital stack you are focused. There is less cash to borrow against, so the amount of back-levered debt that can be raised is decreasing. If the electricity price under the PPA increases over time, you have a snowball effect where the amount of cash available in the early years is not enough to service the debt. Turning to tax equity, the reduction in the corporate tax rate means that tax equity investors require more cash to make up for the loss in value of tax losses.

MR. MARTIN: So you must need more equity in the capital stack because you are not raising as much tax equity or debt. What is your typical capital stack? What percentage tax equity, debt and true equity?

MR. VERSTYN: It is 30% to 40% tax equity, 30% back-levered debt and 30% sponsor equity or maybe a little less on the sponsor side. In the good old days, it was definitely a lot less. Our investments are done on a full equity basis, so we only source the tax equity portion, and deployment of larger ticket sizes is beneficial to us, so it is not a real problem, but even in the levered deals, you still need a lot of sponsor equity.

MR. PLAXICO: I agree. We have also seen investors who plan to be the long-term owners purchase assets on an unlevered basis. They get rid of the back leverage. Along with less cash in deals, PPAs are getting shorter, so are these investors able to break even by the end of a 15-year PPA term? Maybe. Will they break even when PPA terms are 12 years? No, and at 10 years, definitely not. Going forward, investors will not get their money back though the contracted period, and a new trend will be how investors adapt to this new reality.

MR. MARTIN: Rob or Shrips what is your typical capital stack?

MS. ILANGO: For smaller assets, it is typically one-third a piece, give or take, on the tax and the cash equity side. One of the disturbing trends we are seeing is utility-scale assets bidding out PPAs in the low single digits. It used to be 3¢ PPAs were good, and then we heard about 2¢ PPAs. I am not sure whether these projects are getting financed.

Now we are seeing the same prices coming to the two- and three-megawatt segment. It is leading to a significant number of stranded assets that are difficult to finance.

MR. MARTIN: Rob Martorano, typical capital stack, one-third, one-third, one-third?

MR. MARTORANO: Yes. That's pretty much what we are doing. We see those same projects. We are bidding into those with a reasonable bid, and the winners are bidding lower at rates where you know they will never be able to make the economics work.

MR. MARTIN: I imagine the weighted average cost of capital is going up in this market because there is more sponsor equity and less debt and tax equity. What do you think it is for utility-scale solar?

MR. PLAXICO: The cost of equity is the range of discount rates I quoted earlier. On the back-levered debt side, rates continue to be extremely low for quality projects: LIBOR plus 137.5 basis points or lower.

MR. VERSTYN: That's about right. On the debt side, we see some compression still on the margins, which helps us out. The supply of tax equity remains good, and then some new players are coming into the market which also drives down the return expectations from tax equity, but not significantly. Tax equity remains the most expensive capital.

MR. MARTIN: That remains a source of frustration for sponsors and lenders who earn less than the tax equity investors and are behind them in the capital stack. Where are current tax equity yields? They seemed to be in the mid-6% range for a while for utility-scale solar.

MR. VERSTYN: We have seen some drift a little lower. Some are a little higher. We see concessions in other kinds of attributes within the tax equity deal that sweeten the pie for us. DRO levels are creeping up a bit, which is helpful. Flip tenors are going longer. The investors are competing with one another for deals and using various levers to do so.

MR. MARTIN: What is the weighted average cost of capital for C&I and community solar projects?

MR. MARTORANO: We are seeing somewhere in the 7% to 8% range, but on a levered basis. It is all really a matter of what the assumptions are going in. Everyone has a different return requirement. You hear that a project went off at a seven, but, when you back into what the numbers are, it may not actually be a seven. Everyone basically has his or her own assumptions. The numbers may be as low as 6% to 6.5% to 10% levered.

MS. ILANGO: Based on what Vince was talking about from an underwriting standpoint, a 35- to 40-year life with a third-party market-based merchant curve on the back end, you could safely add a couple hundred basis points to the utility-scale number, so 9% to 10%.

MR. MARTIN: Are any of you seeing front-levered debt — debt ahead of the tax equity —or is it all back-levered at this point?

MR. MARTORANO: We do both.

MS. ILANGO: We have seen both. Back-levered is our preferred choice just because it gives us a little more flexibility as we build out the portfolio and want to manage the sponsor side better.

MR. VERSTYN: On the utility-scale side, we see only back-levered debt. While there may be interest in front leverage, forbearance has been so difficult to work out that front leverage is really painstakingly costly and time consuming.

MR. MARTIN: Rob Martorano said that he is getting the benefit of the depreciation bonus by doing sale-leasebacks. Are any of the rest of you able to get tax equity to price in a depreciation bonus?

MR. PLAXICO: Not yet.

MS. ILANGO: No.

MR. VERSTYN: No.

MR. MARTIN: Say your name and affiliation, then your question.

MR. WALKER: Chris Walker with GRID Alternatives. You have been great witnesses under this cross examination. [Laughter] What opportunities do you see to be innovative in how these projects are financed?

MS. ILANGO: If I can take a contrarian view to that . . .

MR. MARTIN: There is none? [Laughter]

MS. ILANGO: Solar has succeeded in becoming extremely boring. If you look back 10 years ago, it was the cool place to be. There were SRECs. California was doing something funky. Now pretty much every state in the US has some program to incentivize solar, some kind of net metering (whether it is successful or not), some kind of a community solar program, and a lot of utility scale.

The real value-add is to take the risk away from the solar assets and not make them riskier. That is where solar has succeeded.

People who are trying to earn a better return do so by taking more risk, maybe in terms of doing more innovative community solar financings or adding storage to their assets, for example. But plain solar, in my view, should be plain vanilla and then you can start adding other factors / *continued page 44*

Solar developers are being pitched loans to stockpile equipment to start construction of projects for tax purposes. Solar panels are in short supply.

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to get better returns.

MR. PLAXICO: One innovative feature is we used an insurance policy yesterday as part of an M&A transaction.

MR. MARTIN: Was it reps-and-warranties insurance?

MR. PLAXICO: It was a first-of-a-kind policy.

MR. MARTIN: To cover what risk?

MR. PLAXICO: Let's chat later. [Laughter]

In terms of mitigating risk and finding ways to be innovative, it is not just finding new sources of capital that are cheap. It is also finding ways to make your project more valuable (if you're a seller like we are) for investors.

Opportunity Zones

MR. MARTIN: There has been a frenzy among consultants about opportunity zones. Do you see any role for opportunity zones in your capital structure?

MR. VERSTYN: Not yet. It is another tool that we may be able to use by setting up an early fund ourselves and basically trying to invest. As we expand our footprint and look for new areas, we see that solar projects are often in lower-income areas. We have seen appreciation in value of property in areas that have been designated as opportunity zones.

MR. MARTIN: So the land is more valuable because of the designation.

MR. VERSTYN: Correct.

MS. ILANGO: There seem to be a lot of constraints around what qualifies as an opportunity zone project. I sat through an opportunity zone panel earlier and they were talking about a 90% qualified asset test, a 50% gross income test, a 5% cap on financial assets and other tests, and it just seems like a lot of constraints for a solar asset to hit. I will be curious to see how much opportunity there really is in the solar market for those kinds of funds to invest.

MR. MARTIN: So this is one area where finance is not boring. [Laughter]

MR. PLAXICO: I missed the panel earlier, but a pitch deck I was sent talked about a 13% to 14% return, and that is before the tax benefits that one would get for investing in the opportunity zone. These types of returns will be hard to achieve in utility-scale solar.

MR. MARTIN: Are any of you adding storage to your projects? If so, how is that complicating the financing, if at all?

MR. VERSTYN: Yes. I think 90% of our projects going forward will probably have a storage component unless it ends up complicating things. It depends on the use case.

MR. MARTIN: Give us a sense of the math. If you add storage, presumably you are increasing the cost-per-installed megawatt of the project, but you must be earning more revenue to offset that. How does the math work?

MR. VERSTYN: It depends on the time at which storage is going to be put in place. If you are talking about a 2023 versus a 2021 asset, the investment required for storage could be fundamentally different.

One of the things that the whole industry is examining is where solar panel prices were 10 years ago with the expectation that storage costs will follow a similar trajectory. The cost of deployments in 2022 or 2023 should be significantly lower than it is today.

MS. ILANGO: There is a lot of work to be done by the developers to pick the right technology, pick the right use case, and then convince the financing parties that this is financeable. We look at the SMART program in Massachusetts. The program makes the addition of storage more financeable from a revenue standpoint because you get a fixed fee for adding storage. The expectation is that the market will figure out how to earn other revenue. It is a little bit of risk sharing. The jury is still out, but it will be a good test case for the next year.

MR. MARTIN: But the math. I'm still hazy on the math.

MS. ILANGO: In the SMART program, you get another 3¢ to 7¢ per kilowatt hour for adding storage. Most developers are planning on adding lithium-ion batteries.

MR. PLAXICO: I second that. Lithium-ion from our perspective should not add any incremental technology risk. We are getting a capacity payment for the battery under existing PPAs for two 150-megawatt solar-plus-storage projects with two community choice aggregators in California.

Late-Night Worries

MR. MARTIN: Last question. What solar-related fears keep you awake at night?

MR. VERSTYN: I don't know if it is solar-related necessarily, but policy changes. Just look at the last two years for the kind of changes in tax law and tariffs that have affected our industry. The changes have been fundamental. The ongoing trade negotiations with China could have a huge impact.

MR. MARTIN: So you are worried about the policy getting worse.

MR. VERSTYN: Worse or better. It is the unpredictability of where policy will go.

MR. MARTORANO: I agree. It seems every year we adjust to one fundamental change and then another thing hits. It is trying to anticipate what that can be and then figuring out what it means for projects as you are lining them up, especially ones that take a while to develop.

MR. MARTIN: From where do you think change is mostly to come? The competition among different types of generators is playing out in many different places: for example, in the zero emissions credits that some states are offering to keep nuclear power plants operating, the Perry proposal to keep coal plants operating, the MOPR proceeding at the Federal Energy Regulatory Commission to address the prices at which renewable energy projects can bid into the PJM capacity market. The government had a finger on the scale until recently in favor of renewables. Are you worried it will shift to the other side of the scale?

MR. MARTORANO: Yes. I worry about what might happen over the next two years.

MS. ILANGO: Since we play in the distributed and community solar space, we rely a lot on state-level regulations, so the rate of change in which states implement programs to incentivize solar development is something that I think about a lot.

MR. MARTIN: Are things improving or getting worse?

MS. ILANGO: Getting better. We see a lot of activity even in the non-coastal states, which is long overdue.

MR. PLAXICO: I stay up late at night if a transaction has not yet closed. Major fluctuations in third-party reports and other market dynamics can significantly alter the value of a project. ◎

Energy Storage: Warranties, Insurance and O&M Issues

Standard warranties for lithium-ion batteries covering both performance and defects are two years, but extended warranties can be purchased. A warranty beyond 10 years does not make sense because so much of the battery would need to be replaced after year 10. Insurance can also be purchased. Operations and maintenance of batteries is complicated because the operator relies on software to optimize performance. Rates of deterioration of the battery depend on how the battery is used. A group of storage experts and a tax equity veteran talked about these and other subjects at Infocast Storage Week in San Francisco earlier in the year. The following is an edited transcript.

The panelists are Jon Cozens, chief commercial officer of New Energy Risk, Sam Jaffe, managing director at Cairn Energy Research Advisors, Neil Maguire, CEO of Adara Power, Carl Mansfield, general manager of NantEnergy, and Ed Rossier, director of project management and renewable energy investments at US Bank. The moderator is Deanne Barrow with Norton Rose Fulbright in Washington.

Warranties

MS. BARROW: Let's start with warranties and insurance products that help storage projects get financed. Jon Cozens, your company, New Energy Risk, underwrites technology performance. How does it work?

MR. COZENS: Take any energy generating asset, not a storage asset, that has a nameplate output of 100 units. That asset is put into the field, and the output is sold. Imagine financing is obtained from a bank, and the bank requires a debt service coverage ratio of 1.0. Suppose that satisfying this requirement requires the asset to produce at least 60 out of the 100 units of nameplate output per quarter. We simply insure that the asset will produce 60 units in every quarter for the entire term during which the debt amortizes. That was our baseline insurance warranty product. Insurers always look for balance-sheet support. They look for a developer to make a guarantee that is similar, if not stronger.

Pivoting into the storage world, there are usually two types of warranties. First, there is usually a product warranty, which is a guarantee against defects. The warranty provider promises to repair the product if there is a defect. We do not focus on this type of warranty so much.

The second type of warranty is a performance warranty. This is our main focus. In storage, we insure four key attributes of a system over time. These are capacity, energy or power, availability and round-trip efficiency, or some combination of all of those.

Building on that, we have had success insuring demand-charge reductions. This product ensures forecasts by energy service companies of peak demand, making the battery available, with the right stated charge both to charge or discharge as required, and having an algorithm that accurately predicts the peak and reduces demand charges. That sums up the evolution of insurance products we have seen over time.

MS. BARROW: Sam Jaffe, it is difficult to model and predict degradation and deterioration over time. How then do you provide a warranty that guarantees output?

MR. JAFFE: That question needs to be answered. It is not answered fully today.

One option is self-insurance. This is where the developer says, "if the battery fails, in six years' time, we are going to back it up with our balance sheet." It is not a financially smart move for the developer, the power purchaser or the cell manufacturer. Self-insurance is being phased out, but I know of situations where it is still used.

The other way to do it is to oversize the system. If the developer has contracted to provide a certain amount of power over time and is concerned that in year eight or nine, the system will not be able to deliver the required power, it will just build a bigger system. Again, this is not an efficient way of doing it. There needs to be a robust, financially stable insurance market for these products that goes beyond just the battery manufacturer's one-year warranty, which is really not of value.

MS. BARROW: Carl Mansfield, NantEnergy offers a novel rechargeable zinc-air battery. Lithium-ion has emerged as the dominant technology, but the storage industry is bursting with innovation. Speak to the role that warranties and insurance play in new technologies gaining a foothold in the market.

MR. MANSFIELD: While we have a novel zinc-air battery technology, which has made some pretty amazing progress over the past decade, we are still deploying lithium battery technology in our projects. We also have hybrids that combine lithium and zinc-air together.

The major advantage of the zinc-air product is that it is optimized for very low cost, long duration for backup, and so it is ideal for lead-acid or diesel-generation displacement. We announced last year that we have broken the $100-per-kilowatt-hour cost barrier on that product.

As far as new products are concerned, we are both a buyer of batteries, where we get the warranty the vendor provides, and also a manufacturer of batteries, where we have to provide warranties ourselves.

Most manufacturers will sell an extended warranty if the purchaser wants it.

Standard warranties for lithium-ion batteries are two years, but extended warranties can be purchased.

The standard warranty today is two years, both for performance and as a general product warranty. Most projects that are financed need a longer warranty.

There is a particular challenge in the commercial and industrial solar market, where the primary purpose of the battery is to provide demand-charge management for the C&I customer on whose premises the battery is installed. A warranty from the vendor guaranteeing that in 10 years, the system will have 75% of year-one capacity is all well and good, but it provides no value to the host customer. You could have 150% of year-one capacity at year 10, but if the system is not being dispatched correctly, it delivers no value to the host customer.

Whether or not the storage technology is novel, the warranty will always depend on the application. If the battery will be used for a telecommunications application at a cell tower, and it needs to have a system life of five years or 10 years and a specific expected cycling, then we can guarantee the system will meet those requirements.

MS. BARROW: Adara Power, formerly known as Juice Box, deploys lithium-ion batteries. Neil Maguire, do you have any thoughts on predicting deterioration and how warranties can be provided around deterioration?

MR. MAGUIRE: I used to work at a lithium-ion cathode material coating company making 18650 cells. Those are small cylindrical cells of 18 millimeters by 65 millimeters in size that were first introduced in 1991. We are now in year 28 of lithium-ion cells. We could put those cells under different temperatures and different C-rates, meaning the amount of current you push and pull, and we could get almost any life cycle you want out of the battery. It is all about how the battery will be used.

A company like LG Chem will provide an energy throughput warranty. What this means is that it warrants that the battery will deliver a certain amount of energy over a 10-year life.

The number of times a day the battery is cycled will affect how many years of use you can get out of it. So the energy throughput is key. LG Chem requires the operator to maintain the battery at a certain temperature and state of charge — do not keep it all the way up or all the way down — or that voids the warranty. The warranty comes with many conditions obviously written by an electrochemist in South Korea. The conditions put the onus on the operator to track the data to protect the customer and to enable it to go back to LG Chem with proof that the system was controlled in accordance with the warranty conditions.

MS. BARROW: Can you share any best practices for tracking and storing data that could be needed to make a warranty claim?

MR. MAGUIRE: The battery vendor will have a very specific list of data that it requires. It will usually want to see data logged at 15-minute intervals. It will want to see the maximum current running through the system for a period and the minimum and maximum state of charge / *continued page 48*

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of the battery. The data is tracked with a software controller and stored on the cloud. With Amazon Web Services' cloud repository, for example, you can scrape off the relevant information for a warranty claim and, at a moment's notice, produce a report for LG Chem or Samsung.

Tax Equity Concerns

MS. BARROW: Ed Rossier, you are a tax equity investor. What most concerns you when evaluating a storage project that is looking to raise tax equity?

MR. ROSSIER: We worry about catastrophic failure, but we also have some upside risk that is dependent on optimizing operations over a longer term. We focus on what might happen to cause the downside or prevent the upside from occurring.

If the project is expecting to receive an investment tax credit that is dependent on not charging the battery from the grid, then the big risk we worry about is what controls are in place to ensure that that there is no grid charging. IRS guidance is not clear about how that should be shown. The industry, collectively, is still trying to decide what needs to be shown in the event of an audit. The investment tax credit recapture provisions are draconian in the case of energy storage.

The last panel talked about the desire for flexible use cases and how some projects are built without knowing exactly how they will be used. That is a little challenging from our perspective because if the industry is going to scale, it needs to get the story straight. Bankers are inherently lazy, and we already have to deal with tax equity, which is really complex. I have three kids under seven, so I may have 2% of my brain left to understand the energy storage warranty, and the warranties we have seen so far are really complicated and seem to be individually negotiated.

We have to process the complexity of the warranty terms, where the risk is allocated, the creditworthiness of the entity standing behind the warranty and potential changes in use cases over time. That is a lot to get through on any individual project.

MS. BARROW: Digging deeper on the ITC recapture risk, what kind of metering data should a battery operator keep in case the IRS audits a project? How do you prove that the battery was charged, at least 75% or more of the time, not from the grid, but from a renewable energy source, so that you are eligible for the ITC?

MR. MANSFIELD: To begin with, we do not claim that the battery is charged 100% of the time from the on-site solar. We usually claim around 90%, depending on the site. Our approach is to conduct extensive metering and logging of data at all of our sites so that we capture and store energy production data, both from the solar and in and out of the battery in real time.

Our view is that a 15-minute interval calculation on an annual basis is sufficient to provide an audit-proof claim that you are meeting the requirements for ITC eligibility. We have had an independent third-party review of our approach, and it concurred with our opinion.

MR. MAGUIRE: To meet a target of 100% charging from solar, we produce data that shows how much solar power is produced each day, as well as data showing when the battery was charged. Those two data sets can then be overlaid.

It is important for the data to be available if the IRS ever comes, but I know of no case so far where the IRS has ever asked for such data. I am not sure that it would know what to look for right now, with all due respect.

MS. BARROW: Ed Rossier, are you comfortable with claiming an ITC assuming full solar charging?

MR. ROSSIER: The projects we have financed so far have been behind-the-meter, residential projects. The Massachusetts SMART program seems to be driving the current interest in tax equity for solar-plus-storage projects. We are just starting to look at projects that are not strictly residential. In the beginning, residential solar systems for the most part could not be charged with grid power, so there was no control needed other than the design of the system. That is starting to change. If a system is able to charge from the grid, then we would expect some kind of buffer.

MR. MANSFIELD: The decision about how much ITC it is reasonable to claim should also depend on the application. A system that is providing demand-charge management for a C&I customer can technically charge 100% of the time from on-site solar, but doing so will sacrifice performance of demand-charge management. On the other hand, if the system is providing standby backup power only, without demand-charge management, then it is possible to get pretty darn close to 100% solar charging.

Battery O&M

MS. BARROW: Switching gears, Neil Maguire, the complex part of operations and maintenance is the operations part, not the maintenance part. Why is storage different from, say, solar,

Warranties of more than 10 years may not make sense since too much of the battery would need to be replaced after year 10.

where O&M is somewhat commoditized?

MR. MAGUIRE: Maintenance for solar projects is very well understood at this point. It involves cleaning the panels and replacing parts that are under warranty, like the inverter or the panels. That kind of maintenance requires going out to the site and incurring direct labor costs.

With a battery, there will be some outdoor systems such as an HVAC or air-conditioning system with filters. There will be maintenance requirements for that equipment, but other than that, site visits are only necessary to check fuses and connections, and to take voltage and current measurements. The maintenance part does not involve a lot of direct labor.

The operation of the battery is far more complicated because it involves tracking data for the warranty, as we discussed, and also operating the system in such a way that it achieves the demand-charge management or the peak-shifting performance that has been guaranteed to the customer.

This requires manning a network operating center to look constantly for inverter faults or communication gaps. There is a lot more interaction with the system. On top of that, certain modifications may be needed to reflect electricity tariff changes. For example, on March 1, new tariffs became effective in California. They are rolling out over the next year. Firmware updates will be necessary at that point to modify when the battery charges and discharges, and at what rate. Storage requires more effort. It requires a lot of fine tuning.

MR. COZENS: I agree. Before the illustrious world of insurance, I was in the energy procurement department at Pacific Gas & Electric and Southern California Edison, back when solar was $130 a megawatt hour.

Maintenance used to involve Windex and paper towels. It is totally different now. When setting up a warranty — and if you choose to use insurance behind it — you should think through how the battery should perform, the different temperatures it will be subjected to depending on different conditions at the site, and how it will be maintained.

MR. MAGUIRE: If the system is third-party owned, the O&M treatment means going to the site to verify the efficiency and the output of the equipment, not just a general changing of filters and other physical tasks. The O&M agreement should require the manager to make sure the system is hitting efficiency and other performance numbers.

MS. BARROW: What kind of costs are we talking here? Can you give us a benchmark?

MR. MAGUIRE: That is a little tougher. If you buy enterprise software, it will come with a maintenance agreement, which is normally 12% to 18% of the total cost. That pays for firmware updates. If new electricity tariffs or new use cases come out, then you have software people who are making changes and rolling out firmware updates. Part of the O&M fee is to fund continual, sustaining engineering on the firmware.

The other part is sending people out to sites. I would say the cost is in the range of 3% to 5% of total project costs per year for the O&M on energy storage.

MS. BARROW: Does anyone have different numbers?

MR. ROSSIER: I agree with the prices. They are consistent with what we have been quoted.

We have encountered challenges around software. Software is provided as an ongoing service contract, and one of the concerns we have is what happens if the software provider decides to pivot or goes bankrupt and can no longer provide the service. Who steps in, and what does that look like from an investor standpoint? There could also be a hardware component. Do you have to find a competitor, and are there enough competitors that are reliable and proven in the US that we can swap out the O&M contractor? How long would that take, and how do you plan for that possibility?

MR. MANSFIELD: Software is one of the fundamental differences between storage and solar. Solar has fewer moving parts because it gets deployed in the */ continued page 50*

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field and is left alone. You clean it and that is all you have to do.

With battery storage, you can have a system with 100% of year-one capacity, but if the software does not dispatch it correctly, it will not produce savings for the customer.

If the company —- large or small — that wrote the software and was managing the system goes bankrupt, it would be challenging to replace that control. You would have to rip out the control and put in a new system that is capable of interfacing to the onsite hardware. That is your only real option.

Compare that to solar where O&M is a commodity. You can just shop it around. If an O&M provider or the developer that built the project and is doing the O&M is no longer around, it is easy to get a new O&M guy before anything has to be done at the site. With storage, some downtime will be required.

MR. MAGUIRE: I agree. We are a small private company, but in the time I used to be sitting on panels at these conferences, some larger solar companies like Sungevity, SunEdison and SolarCity have consolidated or collapsed.

Even though we have great software engineers, we cannot take somebody else's code and figure it all out and start maintaining it. We would have to pull out the controller, install a new industrial computer and have a Modbus interface to the inverter. If the inverter is not one with which we are already familiar, then it could end up being a three-month effort before we take control.

If the software provider goes out of business, the system will not stop working immediately. There will be time to swap out hardware and software.

MR. MANSFIELD: When we are underwriting storage projects, we have an independent engineer evaluate the contracts, the scope and the qualifications of the software provider. I am not completely convinced the IEs are really able to underwrite software and controls. It is something that gets pushed into their scope of work, but it is not the core competency of a lot of IEs to speak to software capabilities.

MS. BARROW: Sounds like a call for IEs with software engineering and computer coding knowledge. Given the importance of software, is there a place for escrow agreements? They require the software provider to put its code in escrow with a third party, and the code is only released if something happens to the provider.

MR. MANSFIELD: We have not done that with our software and we have not had someone ask us to do that. I am not sure that we would want to do that.

MS. BARROW: Why not?

MR. MANSFIELD: Because of the complexity and overhead cost. The approach that we have taken historically at Sharp Electronics and now NantEnergy is to convince customers that our solution is bankable.

MR. COZENS: There is always an intellectual property angle, whether it is a royalty-free, nonexclusive technology license that is given to lenders and insurers or putting the intellectual property into escrow. This is true of just about every storage deal we have done.

Data Points

MS. BARROW: I would like to move into a segment we will call "rapid fire" because I have a series of short questions. The idea is to establish some data points that may be useful to the audience.

Beginning with length of warranties for a lithium-ion battery, I heard that someone on an earlier panel say two years is standard, and I heard someone else say one year. What is standard? Sam Jaffe, start with you.

MR. JAFFE: It could really be anything depending on how much you pay, but the

Degradation rates depend on how batteries are used.

traditional lithium-ion manufacturer warranty that comes out of the box is going to be one or two years.

MS. BARROW: What is the standard length of capacity maintenance guarantees?

MR. JAFFE: That is when you get into extended warranties. Capacity maintenance guarantees are project-specific and get negotiated with the manufacturer. Negotiation only works for very large projects. Guarantees for residential projects are not typically negotiated.

MS. BARROW: Does anyone have different data?

MR. MAGUIRE: In C&I projects, capital costs for storage systems range from about $500,000 to $3 million, and we have to give a 10-year warranty. To qualify for incentives under California's self-generation incentive program, every piece of gear needs a 10-year warranty.

We typically get a three-year warranty from the LGs and the Samsungs of the world, and an extended warranty can be purchased to cover a total of 10 years. The standard warranty is 10 years but, as Sam said, there is a cost to it.

MS. BARROW: In terms of cost, is it proportionately more expensive to extend the term beyond the 10-year standard? Would the additional cost of a 15-year warranty equal the cost of a 5-year warranty or does it not work like that?

MR. MAGUIRE: A warranty is provided with a design target in mind. A 10-year warranty will not have a design target of 10 years because half of the batteries will need to be returned under warranty. The design target would have to be at least 14 or 15 years.

I would not give a 15-year warranty, and I do not think anybody in the space should give a 15-year warranty. It would require planning for replacements after 10 years. It is difficult to project ahead what prices will be at that time. Prices are coming down. It could be possible to replace the batteries for maybe 35% of what they cost now.

I think a 15-year warranty is a waste of money.

MR. MANSFIELD: You can get any warranty you want, but the caution I would give — particularly with a lithium product — is to look out for any caveats that give the supplier an out.

Financiers like longer warranties, but for a system integrator like us, longer warranties are not that useful.

MS. BARROW: Sam Jaffe, you work a lot with sizing storage systems to provide capacity under PPAs and other kinds of offtake agreements. How common is it for utility offtakers to allow a certain level of degradation in the required capacity over the term of the PPA?

MR. JAFFE: I have not seen that. A contract will require a certain amount of megawatts to be delivered, and the provider has a duty to provide that amount of megawatts. The system may need to be oversized.

MS. BARROW: We talked about how capacity degradation depends on how the battery is used. Is degradation linear over time assuming the use case does not change?

MR. JAFFE: No. Long-term battery testing data shows degradation is not linear. It tends to be stochastic, and it is hard to predict when a particular system will fail. Obviously if the permissible operating ranges are exceeded, then that will affect degradation, but you can still have unexpected outcomes. Anyone who has certain expectations and a high level of certainty regarding degradation may be surprised.

MS. BARROW: Ed Rossier, when you invest tax equity in residential rooftop or C&I solar paired with storage, what percentage of the portfolio do you allow to contain batteries, and has that percentage increased over time?

MR. ROSSIER: It was low to begin with but, yes, it has crept up over time. It depends on the developer and its balance sheet. Let's say it is 5% of the portfolio. We rely on the developer to make us whole if there are any issues with performance.

MS. BARROW: Would you say 5% is in most cases where things are today?

MR. ROSSIER: I don't want to be pinned down to a number, but 5% is a good target.

MR. MAGUIRE: With the change in time-of-use rates in California, a lot of developers and solar installers are now quoting energy storage in every deal.

Under Southern California Edison's GS3 time-of-use rate, the energy charge during peak periods, which are from 4 to 9 p.m. or 5 to 8 p.m., are as high as 40¢ a kilowatt hour. Demand-charge management is popular, but with time-of-use rates, energy arbitrage is becoming a significant play. Energy storage will be combined with solar to shift output into the evening. This is maybe specific to California with the new time-of-use rates, but 100% of solar contractors are now offering battery storage.

MS. BARROW: One concept that often appears in offtake agreements and credit agreements is change-of-control restrictions. This means if the current owner of the project changes, there are pre-agreed requirements on who will be considered qualified or experienced enough to step in. For solar and wind projects, this could be */ continued page 52*

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expressed in terms of a number of megawatts the new owner must have had under operation or ownership in a recent number of years, say the past three years. Ed Rossier, what benchmarks are emerging for utility-scale storage? What would you consider to be a qualified or experienced owner or operator?

O&M for batteries is more complicated than for a power plant.

MR. ROSSIER: They are still evolving. The qualified transferee or replacement-manager concept is pretty well agreed to in solar, although it is still somewhat negotiated, but I do not think there is a standard yet for energy storage. The expectation is that some very large Fortune 500 company will step in as a new operator-owner. The reality will be something totally different when a deal breaks, but hopefully we are still a little ways off from crossing that bridge.

MS. BARROW: We are down to the last question. What is involved in decommissioning a battery storage facility and disposing of used cells, and what are the costs associated with it? Sam Jaffe?

MR. JAFFE: It differs by country. The European Union has specific regulations dealing with the obligations of the original buyer of the battery to ensure that there is some form of recycling.

However, we are not at the stage where recycling is very real in practice. When it does happen, it tends to be that the battery is burnt and the slag deposited in a recycling pit or landfill.

Disposal is a key potential liability at the end of the life of a battery. In fact, that liability is driving a lot of European carmakers to repurpose their electric vehicle battery packs into stationary storage. It is a way to fob off the obligation to the next guy, plus there is a cost-savings benefit by doing so.

That is the situation in Europe and China, too. I think it is inevitable that North America, or the US, will eventually have similar regulations.

MR. MAGUIRE: The car industry has had to deal with battery disposal before the power industry. A company in Los Angeles called "The Kinsbursky Brothers" specializes in recycling and repurposing electric vehicle batteries. All of the Toyota Prius batteries from all the junkyards go back to the dealers and are then transported down to a recycling facility. Toyota then de-manufacture the packs. It removes plastics and circuit boards to get to the battery itself — in the case of an electric vehicle, nickel metal hydride. Then it melts down the remaining battery and skims off different materials.

Many of the leftover materials have residual value. With lithium-ion batteries, the nickel manganese cobalt is a valuable material. There is less residual value in iron-phosphate batteries, but the disposal process is the same. They are routed back to approved recyclers, de-manufactured and the metals recovered.

MR. JAFFE: Just to be clear, nickel-metal-hydride batteries contain the element lanthanum and other precious metals. However, there is nothing of that degree of value in lithium-ion batteries, except for the cobalt. You can make a lot of money recycling a cell-phone battery, which is lithium cobalt oxide, because about 70% of that battery is cobalt. You cannot make a lot of money recycling nickel-manganese-cobalt batteries today.

MS. BARROW: So depending on the underlying chemical make-up of the battery, the residual product may either be valuable or a liability.

MR. JAFFE: Yes. It depends on the chemistry and also the development of new technologies for recycling, which will be critical for making the process work economically. ◎

Physical Fixed-Volume Hedges

by Christine Brozynski, in New York

Norton Rose Fulbright holds internal training sessions for lawyers in its projects group. The following is from a session in mid-June about physical fixed-volume hedges.

Such hedges might be used in an organized power market, like ERCOT in Texas, where a project sells its actual output to the grid at the current market price at time of sale, and then buys back a fixed quantity of electricity at the market price and redelivers it to a counterparty under a fixed-volume hedge. The project receives a fixed electricity price under the hedge. The arrangement has the effect of converting floating revenue into fixed revenue so that the project can be financed.

A physical fixed-volume hedge is entered in place of a power purchase agreement.

It helps to mitigate the risk that power prices will fluctuate by offloading some of the price risk to a hedge provider.

The hedge provider makes a bet on power prices for the next 10 or so years. A "physical" hedge means that the hedge provider is actually purchasing power as part of the transaction, and a "fixed-volume" hedge means the hedge settles with respect to a predetermined volume of power, regardless of the amount of power actually produced by the project.

The terms of these transactions are usually spread over five separate documents using ISDA, or International Swap and Derivatives Association, forms.

The "Confirmation" has the main commercial terms, including what is sold and for what price. The "Master Agreement" has all the legal terms, such as events of default and representations. The Master Agreement cannot be revised directly; instead, it is revised through a "Schedule," which is a separate document in which the parties make certain choices or elections and also list any amendments to the Master Agreement. Finally, a "Credit Support Annex" governs credit support and, like the Master Agreement, is not negotiated. The parties can make elections under and amend the Credit Support Annex in a separate document called "Paragraph 13 to the Credit Support Annex."

The Confirmation

The Confirmation has a general description of the commercial transaction.

One key element in the Confirmation is the "shape."

The shape is the fixed-volume part of the physical fixed-volume hedge. The hedge settles with respect to a fixed predetermined quantity of megawatt hours of power, regardless of how much power the project produces that hour. Production at the project is separate from the quantity settled under the hedge.

The granularity of the shape varies. A 12 x 24 shape, for example, is a grid with one column for each month and one row for each hour of the day. For the entire life of the hedge, every midnight to 1:00 a.m. in January, the hedge will settle with respect to the quantity of power in the first column (January) and first row (the hour ending at 1:00 a.m.), regardless of the amount of power produced by the project that hour.

The shape is designed to reflect projected P99 volumes at the project. P99 is a very conservative estimate of production. It means that there is 99% chance that the project will produce those volumes. A less granular shape might show, for example, January and February in a single column, or midnight through 4:00 a.m. in a single row. Often a project company will push to do a 12 x 24 matrix because that allows it to tailor the shape more closely to the expected fluctuation in wind.

The Confirmation also describes the terms of the "physical settlement."

Physical settlement means there is physical delivery of electricity to the hedge provider under the hedge. The power sold under the hedge is not the same as the power produced by the project, which is produced and sold into the spot market at a "node" where the project connects with the grid. The project company buys back power at a "hub" for the current market hub price and then immediately resells that power to the hedge provider for the agreed fixed price.

The price that the project receives for power at the node reflects the supply and demand at that time and also reflects conditions at the node such as grid congestion.

A concern that many hedge providers have about the node is the node does not reflect the true market value of power because of congestion-related and region-specific variations that may have nothing to do with the value of power. In response to this concern and to encourage trading, some grid operators created "hubs." */ continued page 54*

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A hub is an artificial mechanism to establish a market price for power over a large area without fluctuations due to congestion and other factors unrelated to the value of power. It is designed to mimic liquid trading hubs for commodities like the Henry Hub for natural gas. There are different ways to design and organize a hub; for example, a grid operator might take several nodes that are relatively uncongested and then average those nodal prices, with the average then becoming the hub price. Hedge providers are comfortable using the hub price because it reflects the market price of power and is hopefully liquid enough that other parties will enter into back-to-back trades.

The project company uses merchant revenues received at the node to buy power at the hub. The project company is required to buy the hourly quantity of power at the hub shown for that hour in the shape attached to the Confirmation. For example, for the hour between midnight and 1:00 a.m. in January, the project company would be required to purchase the megawatt hours of power set for that hour in the shape, regardless of what the project produced. The project company pays the hub price for that power and then immediately resells that power to the hedge provider for the agreed fixed price per megawatt hour.

This type of transaction gives rise to basis risk.

Basis risk is the risk that the nodal price per megawatt hour, representing actual project revenue, is lower than the hub price per megawatt, which is what the project company pays to buy back the power it needs to sell under the hedge.

ERCOT has had significant basis issues for the past few years. Project owners usually end up taking basis risk. The owner can manage basis in the short term with congestion revenue rights, but the market has yet to offer any long-term solutions, likely because nodal prices are so unpredictable.

One temporary solution is a "tracking account."

Recall that there are two main mismatches between what happens at the project and what happens under the hedge. There is a price mismatch, also known as basis risk. The second mismatch is the volume and shape mismatch.

Production at the project will not always line up with the required hourly quantity in the shape. The hope on the sponsor side is that the project will generate more electricity than the amount shown in the hedge shape, since the shape reflects P99 output. For example, in wind projects, wind speeds vary from one hour to the next, so there is also a good chance in any given hour that the project will underperform or overperform.

One solution the market has settled on to offer temporary relief is a tracking account. The tracking account is documented in the Confirmation and functions as a working-capital loan from the hedge provider to the project company in the amount of these mismatches. As shorthand, the "mismatch" is usually defined as the difference between project company revenues at the node for a given month and the amount that the project company had to pay out under the hedge in a given month. Hedge providers will lend the project company the amount of the mismatch, up to a limit. In a given month, if the project company revenues exceed what the project company was required to pay under the hedge, then the project company must apply the extra funds to pay down the tracking account. The project company must repay any outstanding loan balance at the end of the term. Often the sponsor negotiates for a structured repayment over the course of two or three years.

The Schedule

The following are a few of the commonly negotiated points in the Schedule.

One is "additional termination events."

These are some of the most highly negotiated provisions in the Schedule and are the events that allow one party to terminate the hedge. Often these end up being project-specific events that give rise to a termination right for the hedge provider. For example, the parties might agree to include a failure by the project to reach commercial operation by a specific date.

Another area for negotiation is "incremental hedging."

The sponsor may want to have the project company enter into additional hedge agreements to cover other types of exposure. For example, the project company could enter into a supplemental hedge called a "balance of hedge" to address covariance risk or another arrangement called a "unit-contingent option" to cover price risk on volumes produced at the project in excess of P99 volumes.

Sponsors interested in pursuing these options should consider building the flexibility to do so directly into the Schedule.

Typically the hedge provider will add boundaries around the permitted additional hedges. If the sponsor anticipates that it may want to grant a lien as credit support under any incremental hedges, then a lien cap for the incremental hedges should be negotiated before signing the fixed volume hedge. The sponsor should also consider attaching a form of inter-creditor agreement to the hedge to be entered into by the hedge provider and any incremental hedge providers.

Another area for negotiation is called a "supplemental collateral condition."

It is a feature in many renewable energy hedges where the project company negotiates for the right to avoid termination of the hedge after certain defaults or termination events by posting extra collateral. The extra collateral is the amount of the hedge provider's exposure, meaning how much the hedge provider would be owed if the hedge were terminated at that point in time.

The theory is that if the project company is posting a letter of credit to cover the hedge provider's exposure, then the hedge provider would not need to rely on the collateral in the event the hedge were terminated, so safeguards are no longer needed in the hedge to protect the collateral. The parties end up negotiating what specific events of default and termination events can be cured by the project company electing a supplemental collateral condition. Some hedge providers will require that, in addition to posting collateral in the amount of its exposure, the project company post a small independent amount to cover any fluctuation in its exposure between valuation dates.

Another negotiated term is a "partial unwind."

A partial unwind is a partial termination of the hedge. The theory behind this is that the hedge should cover P99 output at the project, so if at any time the project shrinks, the volumes in the shape will be greater than P99 and the project will be overhedged.

An overhedged project poses a liquidity issue for the project company and a credit issue for the hedge provider.

The solution is to reduce the volumes in the shape proportionally with the reduction in nameplate capacity of the project: this is called a partial unwind.

For example, if a casualty occurs and reduces the project's nameplate capacity from 100 megawatts to 80 megawatts, and the project company chooses not to rebuild, then the project is 20% smaller than originally planned. Because the shape no longer represents P99 output at a project that is 20% smaller, the parties can partly unwind the hedge by reducing each of the hourly quantities in the shape by 20.

Because a partial unwind is a form of partial termination of the hedge, one party will owe the other party a termination payment on account of the reduction in the hourly quantities.

Many different facets of the partial unwind are negotiated by the parties, including the following: (1) under what circumstances a partial unwind can be elected, (2) which party has the right to elect the partial unwind, (3) whether the elections are temporary or permanent, (4) whether the tracking account limit is reduced as part of the unwind, and (5) whether a partial unwind termination payment owed by the project company can be paid over a period of time.

The parties also usually end up negotiating to what extent the hedge provider has approval rights over whether and how the project is rebuilt after a casualty event.

Project company covenants also are negotiated.

The project company covenants in the hedge are in many ways similar to the ones found in a loan agreement, but they are fewer and less stringent.

They are sometimes attached in a separate annex and sometimes inserted directly into the body of the Schedule. They may include permitted liens, asset sales, investments and similar items.

How stringent they are will depend in part on what type of credit support the hedge provider receives under the hedge. If the hedge provider has a lien on the project, then the hedge provider cares more about what happens at the project, how it is maintained and who else may have a claim on the project assets or revenue, and additional covenants may be included in the hedge as protection. Sometimes the parties negotiate to have these additional covenants apply (and in some cases, have all covenants apply) only after the lien is granted to the hedge provider. Negotiated points include which covenant breaches, if any, are additional termination events, allowing the hedge provider to terminate immediately. Often the parties compromise and list only negative covenants as additional termination events, similar to how a loan agreement is structured. The parties may also negotiate which covenant breaches may be cured by electing the supplemental collateral condition.

Paragraph 13

Several few key points are addressed in Paragraph 13 of the Credit Support Annex.

One is the hedge provider credit support.

If the hedge provider is not an investment-grade or creditworthy entity, its obligations will usually */ continued page 56*

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be backed by a guaranty. If the guarantor is downgraded, there may be some additional collateral provided to the project company.

Typically, if the hedge provider or its guarantor is not investment grade, then the hedge provider will be required to post the amount of the project company's exposure.

Project company credit support is also addressed in Paragraph 13 of the Credit Support Annex.

Typically the project company will provide a letter of credit as credit support during construction. Some sponsors prefer to provide a parent guaranty in place of a letter of credit. Whether a hedge provider will accept this usually depends on the creditworthiness of the guarantor. Frequently the project company will then have the right to substitute that letter of credit with a first priority lien upon commercial operation.

The project company often negotiates a form of letter of credit before execution and attaches the form to the hedge. Other negotiated points include letter of credit defaults that allow the hedge provider either to draw down on the letter of credit or to require the letter of credit to be replaced. Cure periods for letter-of-credit defaults are likewise negotiated.

Project companies should try to avoid agreeing to post variable margin (other than when the supplemental collateral condition comes into play as discussed earlier). "Variable margin" means posting an amount that varies with the counterparty's exposure. Even if sponsors have letter-of-credit facilities that allow them to post variable margin, financing parties often resist this as they usually do not have the means to post variable margin and will not be able to satisfy this requirement in the event they replace the project company as counterparty to the hedge. The supplemental collateral condition is looked at in a different light, as it is thought of as the last resort to prevent the project company from losing the hedge.

Inter-Party Issues

Sponsors that intend to finance projects with tax equity or debt should consider building key inter-party points directly into the hedge.

Tax equity will require forbearance arrangements to be in place with the hedge provider. Some sponsors include these directly in the Schedule rather than wait for these to be negotiated with the tax equity investor later in the process.

The lenders may want cure periods even after the loan facility flips to back-leverage, so sometimes the consent to collateral assignment will stay in effect even after term conversion.

Sponsors may want to require that the hedge provider deliver a consent to collateral assignment, forbearance agreement, estoppel and any required opinions to the financing parties upon request.

On the other hand, a sponsor should make sure that any debt or tax equity deliverables required by the hedge provider are reasonable. For example, hedge providers may want to see a copy of the financing agreement with the lenders or equity capital contribution agreement with tax equity. Sponsors should consider expressly noting in the hedge that these agreements may be redacted for confidentiality reasons before being shared with the hedge provider. ◎

Environmental Update

US economic growth is causing carbon dioxide emissions from sources like factories, planes and trucks to surge.

US carbon dioxide emissions increased by 3.4% in 2018, the biggest increase in eight years, according to research firm The Rhodium Group.

Although fossil-fuel emissions in the US have fallen significantly since 2005, the reductions from natural gas and renewable energy displacing coal-fired power were not enough to offset rising emissions in other parts of the economy.

The Rhodium Group estimates that the industrial sector is on track to become the second-biggest source of emissions in California by 2020, behind only transportation, and the biggest source in Texas by 2022.

Waters of the United States

For the foreseeable future, the regulated community will face a patchwork of different standards by which the government will issue jurisdictional findings for water bodies under the Clean Water Act. The standards vary depending on where a project is located.

US carbon emissions surged by 3.4% in 2018.

The Environmental Protection Agency and the Army Corps of Engineers moved early in the Trump administration to suspend implementation of a regulatory definition of "waters of the United States" under the Clean Water Act that was adopted by those agencies in 2015. Enforcement of this broader definition has been suspended while the agencies finalize a replacement to narrow the scope of the 2015 Obama-era policy.

The Trump administration is pursuing a two-step approach, first by repealing the existing definition and then by replacing it with a more limited standard for when permits are required under the Clean Water Act to build.

The area is now mired in litigation. Some federal district courts have ordered the two agencies not to delay enforcement of the earlier definition, while others have issued orders barring agency enforcement of the prior standard while its legality is litigated.

This has left 22 states subject to the Obama-era rule and 28 exempted from it.

The US Department of Justice initially appealed the decisions ordering no delay in enforcement, but then it changed course in March. It withdrew the appeals it had filed in various courts and urged other courts to dismiss the no-delay cases as moot.

The move guarantees that the law will continue to be implemented differently state by state until the agencies come up with a new definition that survives another round of inevitable court challenges.

While the agencies maintain some discretion on which waters they will subject to Clean Water Act protections even in the 22 states operating under the broader jurisdictional rule, the use of agency discretion to go around the standard may lead to further litigation.

Dropping the appeals could indicate that the agencies are preparing to finalize their long-pending formal repeal of the 2015 rule, but the timing remains uncertain despite EPA's desire to see it done in 2019.

EPA and the Army Corps have proposed a replacement that would significantly narrow the number of water bodies subject to Clean Water Act protection. */ continued page 58*

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The proposal would limit Clean Water Act jurisdiction to permanent or intermittent water bodies with a surface connection to "traditional navigable waters" during a "typical year." It would exclude ephemeral streams, waters with only sub-surface or otherwise indirect connections to navigable waterways as well as wetlands that do not directly touch other jurisdictional waters. It would also abandon a long-standing policy that any interstate water is considered jurisdictional without regard to whether it satisfies other tests.

States

A number of states are using state authority to block the impact of certain federal environmental regulatory rollbacks, including by considering new state-level regulations that will impose pollution control requirements stricter than federal requirements.

For example, California recently revised its state-level regulatory definitions for water bodies that will dull the impact of EPA and the Army Corps adopting narrower Clean Water Act jurisdictional standards within the state.

The rolling back of federal environmental standards is leading to a patchwork of standards that vary by state.

The California Water Resources Control Board approved on April 2 a new definition of what qualifies as regulated "wetlands" and new rules for discharging dredge and fill materials into state waters.

The "State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State" consists of four major elements. One is a wetland definition. Next is a framework for determining whether a feature that meets the wetland definition is a water of the state. Third is wetland delineation procedures. Last are procedures for the submittal, review and approval of applications for water quality certifications and waste discharge requirements for dredge or fill activities.

The board's stricter new wetlands permitting program will effectively block the Trump administration's plan to narrow the Clean Water Act jurisdiction standard in California.

Greater Sage Grouse

The US Bureau of Land Management finalized a plan to ease restrictions on oil and gas drilling on lands that are home to the greater sage grouse.

The Obama administration had previously confirmed 11 state land-use plans for the sage grouse in 2015, but the Department of Interior began a new internal review of those plans in 2017.

The Trump administration finalized revisions to Obama-era greater sage grouse conservation plans in early March. They include a number of provisions that could allow for oil and gas drilling, mining activity and other development near sensitive grouse habitat.

Specifically, the Department of Interior released records of decision, or RODs, based on six environmental impact statements and resource management plans that were revised last year that cover grouse plans in seven Western states.

The plans added certain exemptions from and waivers of mandates in the 2015 plans regarding compensatory mitigation, no-surface occupancy buffers around breeding grounds and seasonal restrictions near bird habitats.

Significantly, the RODs remove mandatory compensatory mitigation for impacts to grouse habitat. The original plans required that disturbance in grouse habitat had to be mitigated to a standard of "no net loss" of habitat. Going forward, BLM will consider compensatory mitigation only when offered voluntarily by a project or if otherwise required by law.

The plans remove most of the 10 million acres of sagebrush focal areas, which the prior plans had identified as critical habitat, leaving just 1.8 million acres of such protected areas.

The decision received bipartisan support from governors in those states where the bird is most common: Wyoming, Nevada, California, Idaho, Oregon, Utah and Colorado.

Critics of the move argue that the amended plans will further disrupt the birds' sagebrush steppe habitat and endanger its survival.

The original plans were considered strong enough that the US Fish and Wildlife Service determined in 2015 that sage grouse did not require protection under the Endangered Species Act, a fact that critics of the revised plans argue is no longer the case.

Various environmental groups are considering legal challenges to the final revised plans.

PFAS

EPA revealed an "action plan" in February to address concerns over contamination from per- and polyfluoroalkyl substances, or PFAS (pronounced "PeeFAS"), emerging chemicals of concern for drinking water in a number of areas around the nation.

The plan provides for more research and initiates some water and waste regulatory steps, but does not set strict policy limits. However, the step could be a first toward nationwide drinking water standards for the chemicals, though not without further delay.

Fluorinated chemicals are commonly added to a wide variety of consumer products to make them non-stick, waterproof, and stain-resistant. These include carpets and upholstery, waterproof apparel, floor waxes, non-stick cookware, camping gear, fast-food wrappers, cleaners, dental floss, and firefighting foams for putting out fuel fires.

EPA says that the chemicals, which persist for a long time in the environment and build up in people's bodies, can cause reproductive and developmental, liver, kidney and immune system problems with sufficient exposure.

EPA Administrator Andrew Wheeler confirmed that the agency is moving forward with a process that could eventually set a maximum contaminant levels for the substances in drinking water.

EPA confirmed the regulatory process for listing two common PFAS as hazardous waste. The goal is to propose a Safe Drinking Water Act regulatory determination for the two most common PFAS, perfluorooctanoic acid (PFOA) and perfluorooctane sulfonate (PFOS), by the end of 2019. This is a necessary step before a maximum contaminant level (MCL) could be set.

The plan also calls for more monitoring of PFAS in water supplies.

The eventual setting of drinking water standards and listing of PFAS as hazardous substances regulated under CERCLA and RCRA would probably lead to significant cleanup liability for responsible parties at sites across the country.

It could even result in responsible parties having to conduct additional remediation at sites where cleanups were previously determined to be complete. Cleanup agreements with regulators regularly include "reopener" clauses to require remediation if the facts on which the resolution was reached change and the cleanup is determined not to protect human health and the environment.

EPA has begun to sample for PFAS at Superfund sites even before it decides whether to list the chemicals as regulated hazardous substances.

In late April, EPA issued long-delayed draft interim guidelines for cleaning up groundwater contaminated with PFAS at levels stricter than what the US Department of Defense has advocated, but not as strict as those being set in some states.

The draft guidance recommends an initial cleanup goal should be set at 70 parts per trillion for PFOA and PFOS for groundwater that is a potential or current source of drinking water, provided no state or tribal drinking water or other state standards exist.

Critics argue that the current draft fails to clarify whether EPA would require remediation of groundwater that states have designated as a future source of drinking water, but where the water is currently not being used.

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The draft does not designate PFAS chemicals as hazardous substances under the Superfund law.

The agency proposed that 40 parts per trillion for PFOA and PFOS should be used as a "screening level" to identify sites with groundwater contamination that may require further investigation.

Whatever EPA does at a national level, a number of states are entering the regulatory field as well. For example, New Jersey regulators set health-based groundwater cleanup standards for PFAS at much stricter levels than those currently being considered by EPA. The state proposed groundwater quality standards of 14 parts per trillion for PFOA and 13 parts per trillion for PFOS, significantly lower than EPA proposed.

EPA Regional Reorganization

EPA has begun a major reorganization of its regional offices that includes significant staff reassignments to new positions.

The plan is reportedly to reorganize regional offices to mirror the divisions found at EPA headquarters.

The realignment appears likely to significantly effect a number of regional offices that have traditionally run their enforcement activities out of program-specific offices, rather than through a dedicated enforcement division. These include as air, waste, water and toxics. ◎

— contributed by Andrew E. Skroback in New York and Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has roughly 3,900 lawyers in 58 offices in 33 countries.

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