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PROJECT FINANCE
NewsWire

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Cost of Capital: 2018 Outlook

The tax equity market managed to function all year in 2017 despite uncertainty about what the US tax code would say. Lenders complained about a shortage of deals to finance. More than 2,400 people listened as a group of project finance industry veterans talked in January about the current cost of capital in the tax equity, bank debt, term loan B and project bond markets and what they foresee ahead.

The panelists are John Eber, managing director and head of energy investments at J.P. Morgan, Jack Cargas, managing director in renewable energy at Bank of America Merrill Lynch, Ralph Cho, co-head of power and infrastructure finance for North America for Investec, Jean-Pierre Boudrias, managing director and head of project finance at Goldman Sachs, and John C.S. Anderson, head of corporate finance at Manulife Financial/John Hancock. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity

MR. MARTIN: John Eber, what was the tax equity volume in 2017, and how did it break down between wind and solar?

MR. EBER: J.P.Morgan estimates it was $10 billion in 2017, so it was down about $1 billion from the $11 billion we saw in 2016. The total volume breaks down to about $6 billion of wind and $4 billion of solar tax equity. Wind was down about $400 million compared to the previous year, and solar was down about $500 million.

There were 15 investors in the wind market in 2017. That is the same number as in the previous year, although there were three new investors who replaced */ continued page 2*

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SOLAR PANEL PRICES are expected to remain high in the first half of 2018, but may ease after that.

Prices early in the year are being propped up by demand in China where projects must be completed by June 30 to qualify for the 2017 feed-in tariff rates rather than the new, lower 2018 rates.

The United States started collecting a 30% tariff on imported solar cells and panels on February 7. The rate will drop to 25% on February 7, 2019, to 20% a year later and to 15% a year after that. Up to 2,500 megawatts of solar cells can enter the country duty-free each year on a first-past-Customs basis. */ continued page 3*

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three who invested in 2016, but did not invest in 2017. There were 27 wind deals in 2017 versus 28 the previous year and 18 different sponsors.

Turning to solar, we saw about $2.3 billion in utility-scale projects, which is almost flat against the previous year, and we saw about $1.5 billion in residential solar as compared to $2.1 billion the previous year. The drop off in residential solar was not a surprise. Many of the residential solar companies were purposely scaling down their growth rates and also promoting sales over power purchase agreements and leases.

MR. MARTIN: You said there were 15 tax equity investors in the wind market. How many in solar?

MR. EBER: Solar is a little harder to track than wind, but our estimate is 15 to 17 in the solar sector. There is overlap, but the investors in the two markets are not identical. We estimate there are about 35 tax equity investors in the market as a whole.

MR. MARTIN: We understand there were 10 other investors in 2017 looking to invest on a syndicated basis alongside more experienced investors. Is that also your count?

MR. EBER: That is possible, but it is not something that we track closely.

MR. MARTIN: Putting the numbers into perspective, I have from past calls annual tax equity volumes of $6.5 billion in 2013, $10.1 billion in 2014, $13 billion in 2015 and, as you said, $11 billion in 2016.

Jack Cargas, was it a surprise that the market found a way to function as well as it did in 2017, given that you had an entire year of uncertainty about what the tax code would say?

MR. CARGAS: We were a little surprised that the market remained as vibrant as it did. There was a lot of competition for specific transactions even though people knew that the hammer was going to fall late in the year.

The only constant in this market over the years has been constant change, and that was certainly the case for 2017. The market found a way to adjust for the tax-change risk. The structures for handling this risk continued to evolve throughout 2017 for the benefit of both sponsors and tax equity investors to the point that projects were essentially protected except for the late curve balls we saw, like the new base erosion and anti-abuse tax and the near miss on the corporate alternative minimum tax.

MR. EBER: One key to why the market worked as well as it did in 2017 is there was growing confidence by late spring that the corporate tax rate would remain 35% through the end of the year. Many of us switched to accelerating depreciation into 2017 by taking the 50% depreciation bonus. That mitigated potential effect of the tax rate change. The rate change was predominantly going to affect the value of the depreciation.

> The competition among banks for deals is keeping downward pressure on interest rates.

MR. MARTIN: In the past, tax equity investors have not been keen to take bonus depreciation. Do you think they will revert this year to past practice?

MR. EBER: The bonus has essentially increased with the 100% expensing. It will be an even heavier lift for investors to take at 100%.

MR. MARTIN: Jack Cargas, do you expect investors to ask sponsors not to take the bonus?

MR. CARGAS: We are still evaluating our position. The calculus has been complicated by the base erosion and anti-abuse tax, or BEAT. This is an area where investors could try to differentiate themselves.

MR. MARTIN: John Eber, what do you expect in 2018 in terms of deal volume?

MR. EBER: I expect it to be fairly constant. The number of projects needing financing in the wind and utility-scale solar markets is continuing to grow. Tax equity volume should remain in the $10 to $11 billion range based on what we are seeing.

MR. MARTIN: Jack Cargas, same sense?

MR. CARGAS: Yes. I think we all predicted a slightly higher volume in 2017. There were various reasons for the slight drop off from 2016. We expect the market to remain flat to slightly up.

MR. MARTIN: We enter 2018 with a lower corporate tax rate of 21%. We have a base erosion and anti-abuse tax that could claw back up to 20% of tax credits claimed in 2018 through 2025, and we have a 100% depreciation bonus for assets put in service through 2022 with a phase-out after that. John Eber, going back to you, how do you expect these changes to affect the market?

MR. EBER: That is a tough one. This is my personal opinion and not a J.P.Morgan official view. I expect tax equity capacity to tighten because there are a lot of changes and they trend toward the negative. The BEAT not only exposes 20% of the tax credits you might be taking on new deals to potential claw back, but it also affects the value of the remaining tax credits across your entire current investment portfolio.

That has to cause some investors to think about how much more they might want to invest versus invest at all.

Then, the drop in the corporate tax rate from 35% to 21% is a substantial drop in overall tax capacity, particularly when you consider that there is a 75% limit on how much an investor can reduce its tax liability with tax credits.

These two changes will affect tax capacity. The $64,000 question is how much and to what extent.

MR. CARGAS: There were also some positive effects from the tax bill. The after-tax returns to project owners should be higher due to lower tax rates.

As for the decrease in tax capacity, you have tax depreciation that is now worth 60% of what it used to be worth. This means that investors will have to think about where to allocate scarce tax capacity across the institution, whether you allocate it to low-income housing or other tax credit businesses and renewable energy finance and, if the latter, whether you have a preference for wind or solar or production tax credits or investment tax credits and what to do about the 100% depreciation bonus. The reality is it is early in the year, and investors are still answering these questions for themselves.

MR. MARTIN: Tax equity has accounted in recent years for 40% to 50% of the capital stack for a typical solar project and 50% to 60% for wind. Do you have a feel yet for where these numbers will settle in 2018?

MR. EBER: I had my team run a few examples. These are from half a dozen live deals on which we are working. On average, the upfront investment in a wind deal looks / continued page 4

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The tariffs are imposed on the importer of record.

The government is required to revisit them after two years.

The last time similar safeguard tariffs were imposed was in 2002 against imported steel. The US removed them two years later after the World Trade Organization authorized other countries to take retaliatory action against US exports. The European Union, China, South Korea, Taiwan and Singapore asked the WTO for compensation in separate filings in late January and early February. The WTO proceedings are expected to take 18 months.

Three Canadian companies filed suit in the US Court of International Trade in early February charging that the tariff violates the North American Free Trade Agreement among the United States, Mexico and Canada.

The Trump administration is expected to publish procedures by February 22 for companies to seek exemptions for particular products from the tariff. In 2002, companies seeking product exemptions had to show that there is no other source of supply for the product in the United States, including other products that can be used as substitutes.

The tariff does not apply to thin-film solar modules. Makers of 72-cell solar modules are expected to seek an exemption. The standard module has 60 cells.

Solar panel imports into the US rose 158% during the period from April, when Suniva first asked for tariffs, through November 2017 as companies rushed to get panels past US Customs ahead of any tariff being imposed.

GTM Research estimates that between 2,000 and 3,000 megawatts of uninstalled modules were in the US at year end 2017, but were already dedicated to projects.

The tariff is not expected to have as great an effect in 2018 as in 2019. New solar construction is expected to fall by 7% in 2018

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like it will be about 8% less with a 21% rather than a 35% tax rate. Tax equity started in the low 60s and is going down into the mid- to low 50% range.

For solar, we see a smaller impact on the order of a 3% reduction. Some of the deals at which we have been looking were in the low-40% range at a 35% rate and are now down to something like 39%.

MR. MARTIN: What percentage of tax equity investors do you expect to be subject to the BEAT? A small number? Large number?

MR. CARGAS: We are aware of one or two situations where tax equity investors have chosen to exit the market at least temporarily and that is due presumably to BEAT concerns. We do not think BEAT will affect a large number of investors. Our firm, Bank of America Merrill Lynch, lived up to all its client commitments last year, but exactly how and where BEAT will affect the market remains open to question.

MR. EBER: I think that's right. It could be just a limited number of investors. However, keep in mind that there may be investors who are still in the market, but who may, as Jack was suggesting earlier, moderate how much they put into renewable energy versus other markets like low-income housing.

MR. MARTIN: For investment tax credit deals, the risk posed by BEAT is that a tax calculation later the same year the investment is made will lead to a claw back of 20% of the tax credit. Isn't this a manageable risk? It is the same risk investors had before of predicting tax capacity for the year of investment. In view of this, do you think investors will give full credit for the investment tax credit in solar deals when deciding how much to invest?

MR. CARGAS: The short answer is yes. Investors are likely to be either in or out on ITC deals and, if they are in, they are likely to give full credit.

MR. EBER: There is a serious question as to whether there will be any carryforward under the BEAT. All the general business credits have carryforwards, which has financial statement implications. This point may cause the market to look at the BEAT risk differently than it did traditional tax capacity risk.

MR. MARTIN: Next issue. It will be possible in 2018 to claim a 100% depreciation bonus for the first time on used equipment. Do you see a move to sale-leasebacks of used equipment as a way for sponsors to raise cash?

MR. CARGAS: We do not expect to see much of this in the renewables market.

MR. EBER: I agree. I don't think sale-leasebacks are likely to come back. The lease-buy analysis is not likely to tilt toward lease at this stage given the low interest rates.

MR. MARTIN: The cost of tax equity is a function of demand and supply. John Eber, you said you think there will be a contraction in supply of tax equity because of the reduction in the corporate tax rate. Jack Cargas, you said there was a lot of competition last year for deals, suggesting that there is low deal flow. Given this, in which direction do you sense yields are moving?

MR. EBER: I hope they are going to stabilize. As Jack said, it was a competitive market last year in which there was more than an adequate supply of tax equity. If my concern plays out in terms of contraction, it is really just a question of how much and how severe. Hopefully, the two curves will remain intersected near the current equilibrium.

MR. MARTIN: If anything, there was downward pressure on yields last year, so stabilize means no further fall.

MR. EBER: The question is answered by the yet-to-be-determined degree of impact of the BEAT.

MR. MARTIN: Are there any other noteworthy trends as we enter 2018?

MR. EBER: We continue to see a lot of corporate PPAs and hedge deals, and one thing we have been noting is that basis risk continues to be a major issue. We think sponsors are underestimating the size of the risk. It is growing in many markets. The issue is in deals with settlements at hubs instead of what happens with a traditional PPA where the power is taken at the bus bar.

MR. MARTIN: Basis risk in this context refers to a difference in pricing. The electricity is delivered in one place, but the price is established in another. Sponsors usually end up with that risk. How does that end up being handled in a tax equity deal?

MR. EBER: It affects the cash flow to the partnership which affects the cash flow that is available for the back-levered lenders and the tax equity. As between the tax equity and the sponsor, the sponsor bears the ultimate risk. However, with electricity prices so low, there is not a lot of excess cash to begin with, and that is putting pressure on a lot of these deals.

Bank Debt

MR. MARTIN: Let's move to Ralph Cho and bank debt. What was the volume of North American project finance bank debt in 2017 compared to 2016?

MR. CHO: Deal volume in 2017 was basically flat compared to 2016. Volume according to Thomson Reuters was about $40 billion spread across 124 deals. This compares to 2016 where we saw about $39 billion spread across 136 deals. The average deal size ticked up a little bit, but the volume was pretty much flat year over year. The market is down about 40% from the 2015 deal volume, which was the last strong year.

MR. MARTIN: How many active banks were there in 2017? How many do you expect in 2018?

MR. CHO: A lot more players came into the bank market in 2017. We estimate there are around 70 to 90 lenders with a number of new players from South Korea. I am including grey market lenders in this count. I expect the number of lenders to remain unchanged in 2018.

There are a lot of lenders looking for these types of deals. Total market capacity, meaning the size of power deal the market can handle at the upper end of the range, is probably about $5 billion and I would even go a little more specific and say of this group, maybe 20 to 30 lenders can probably book loans longer than 15 years and there is enough market capacity on 15-year debt to cover deals of up to $1 billion in size.

MR. MARTIN: LNG project financings were running $10, $11 and $12 billion.

MR. CHO: True. I was talking about power, but lenders definitely can hold much larger tickets on LNG deals.

MR. MARTIN: What is the current spread above LIBOR for bank debt?

MR. CHO: The spread has tightened from a year ago because of the intense competition among lenders for deals.

Plain-vanilla loans have probably fallen from LIBOR plus 1 3/8 to 150 over. Short-term construction loans could even be priced tighter at LIBOR plus 100. That is in the US. In Canada, we have seen pricing as tight as LIBOR plus 125. For whatever reason, Canada seems to get much more aggressive terms.

Quasi-merchant deals have remained amazingly stable at LIBOR plus 325. However, we are starting to see those levels cracking as we enter 2018, and we expect to see them come inside of the 325 level. More interesting to me is the plain-vanilla holdco loans, which traditionally price at LIBOR plus 400 and higher. Today you can probably get those deals done at LIBOR plus 300 to 350 basis points. We are aware of a couple situations where the spread has even been inside of 300. A lot more commercial banks are diversifying and increasing their risk appetite to take on those types of deals.

MR. MARTIN: To what do you / continued page 6

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compared to 16% in 2019 because projects being built early in the year already had secured panels before the tariffs were imposed. It is not clear to what extent the 2019 estimate takes into account the deadline at the end of 2019 for developers to have remaining projects under construction to qualify for an investment tax credit at the full 30% rate.

Modules make up 40% to 45% of system costs.

At least two solar panel manufacturers are looking at setting up manufacturing in the United States using cells imported from Asia. Jinko Solar is expected to choose a location, possibly Jacksonville, Florida, by early March. The company earned a third of its revenue in 2016 in the United States. It signed a contract with an unnamed US customer to supply 1,750 megawatts of panels over three years, which should give it some downside protection were it to open a plant.

Taiwanese panel manufacturer Neo Solar Power said it is also considering opening a plant to make panels in the US.

The United States filed its own complaint in the WTO against India, which it says is discriminating against US products by imposing domestic content requirements in power purchase agreements signed before December 2016. The domestic content requirements are part of a national solar energy initiative. The European Union, Canada and Japan are siding with the US in the dispute.

Meanwhile, the Public Service Co. of Colorado, an electric utility, announced that it will let independent generators who bid into a solicitation in August 2017 for up to 1,800 megawatts, update their bids to take into account the new solar tariff and tax law changes. The company received 430 bids to supply 111,963 megawatts. The median solar bid was $29.50 a megawatt hour for solar without storage and $36 a MWh for solar with

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attribute the large number of additional banks coming into the market last year? A year ago, you and others warned that there is a wall of money chasing deals. That does not appear to have deterred anyone from joining the fray.

MR. CHO: Focusing on the South Korean lenders, they look at the yield opportunity in the US compared to what they can earn in other places. They like the yield. We began seeing them in 2016 in quasi-merchant gas deals, and they liked LIBOR plus 325. But as those deals have started to dry up, they are looking to diversify.

As LIBOR has started to increase, they have been able to do tighter spreads and still earn attractive yields.

MR. MARTIN: What are current loan tenors? You mentioned 20 to 30 banks are willing to go 15 years and perhaps even to 18 years.

The new 21% corporate tax rate means tax equity will supply a smaller percentage of the capital for wind and solar projects.

MR. CHO: Typical loan tenors today are five to seven years with mini-perm features. We see that for a lot of the acquisition financings. Construction loans are obviously much shorter. But for plain-vanilla financings, we have seen banks go as long as construction plus 18 years, especially if the project has a good long-term PPA.

We have even seen back-levered deals go out as long as 15 years. Competition for deals remains strong, and banks want to do these types of deals.

MR. MARTIN: The competition helps. What are current debt service coverage ratios for wind and solar?

MR. CHO: There has not been much change. For wind, the typical DSCR is 1.4x on a P50 basis and 1.0x on a P99 basis for contracted projects. DSCRs for hedged projects are slightly higher. In solar, the ratio is 1.3x on a P50 forecast, and usually you have no problem hitting the 1.0x under the P99 numbers.

MR. MARTIN: Are you seeing any merchant solar deals?

MR. CHO: There is definitely talk about merchant solar where sponsors are looking for value in a residual tail beyond the PPA, especially because people have to take a view if they want to be competitive when bidding to acquire these types of assets. Given the competitive landscape, more and more banks appear willing to accept some amount of merchant tail after the PPA.

MR. MARTIN: A merchant tail, but not an entirely merchant or even quasi-merchant deal?

MR. CHO: A fully merchant deal will still be tough.

MR. MARTIN: Most debt in the renewable energy market is back-levered debt. It is behind the tax equity in the capital structure. You said tenors for back-levered debt are running out as long as 15 years. I assume the coverage ratios are the same as for front-levered debt?

MR. CHO: There is really not much difference between back-levered and front-levered debt at this point. Lenders have not really asked for much of a premium to lend on a back-levered basis. We talk about this among the bankers, and I am not sure it makes sense, but that is where we see the market.

MR. MARTIN: Last year, you said banks have been requiring a 12.5-basis-point premium to lend on a back-levered basis. We heard from some other banks that the premium is 25 basis points. Now it sounds like there is no premium at all.

MR. CHO: You might be able to pick out a couple instances where lenders try to collect a small premium, but for the most part, I don't think a premium is required.

MR. MARTIN: Some lenders during 2017 were considering crediting two to three years of additional revenue past the PPA term as a way of justifying increasing advance rates on loans. That is what you referred to earlier as crediting some amount of merchant tail. In what other ways is the intense competition playing out besides the pressure on yields and merchant tails?

MR. CHO: The pressure is not just in the renewable energy sector. We do this on gas. It is not just PPAs, but also hedges. Banks will take a view based on what they believe a good balloon value can be for the asset. We have seen leverage levels increase as lenders agree to somewhat more aggressive assumptions.

For some banks to be a little more competitive, we have even seen clever ways to increase leverage by shrinking scheduled amortization amounts while maintaining some level of acceptable coverage. The rest of the loan is paid down using cash sweeps. It is a very competitive market for any bank that wants a part of club or syndicated deals.

MR. MARTIN: Are there any other noteworthy trends as we enter 2018?

MR. CHO: M&A and re-pricings will be a significant part of the 2018 deal volume. Greenfield quasi-merchant gas deals — especially in PJM — will be slow. Not zero, but slow. In order to diversify and keep doing deals, lenders have expanded how they define infrastructure projects to create more opportunities for themselves.

We have touched on growing merchant exposure to renewable energy assets. Clean tech is the other trend. These deals still tend to be on the small side, particularly ones with battery storage applications, but we are starting to see a lot more of these types of opportunities.

Term Loan B

MR. MARTIN: Moving to the term loan B market, J-P Boudrias, what was deal volume in that market in 2017, and how did it compare to 2016?

MR. BOUDRIAS: Last year, we saw about $10 billion in volume in the term loan B market in the US power sector. That compares to $7 billion in 2016, so there was an increase. But the increase was timid when compared to the overall B loan market.

The US leverage loan market saw total issuances last year of $938 billion, and that number was up almost 100% compared to the previous year. That number includes $434 billion of repricings. Primary issuances were $503 billion, which was 50% more than the previous year on aggregate. Despite the increase in volume, lenders and investors were looking for product and, as a result, gave permission for a lot of transactions to get repriced.

MR. MARTIN: There were 11 B loan transactions in 2016. What was the number in 2017?

MR. BOUDRIAS: The same count and roughly $6 billion of the $10 billion were repricings. Only $4 billion were new-money deals.

MR. MARTIN: The gross figure of $938 billion was the entire US B loan market?

MR. BOUDRIAS: Correct.

MR. MARTIN: How many 2017 deals / continued page 8

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storage. The median wind bid was $18.10 a MWh and $21 a MWh for wind with storage.

The refreshed bids are due in late February. The winners will be selected in late April.

Prices for contracted wholesale power from wind farms have hit as low $11 a MWh in some places in the Midwest.

VARIOUS ENERGY TAX INCENTIVES were extended by Congress as part of a two-year budget deal in early February.

Developers of geothermal, biomass, landfill gas, waste-to-energy, incremental hydroelectric and ocean energy projects now have the option to claim production tax credits at the full rate on 10 years of electricity output or a 30% investment tax credit on any such projects that were under construction by the end of 2017. The deadline to start construction had been the end of 2016.

Developers of projects using fuel cells, small wind turbines or equipment that relies on fiber-optic distributed sunlight to illuminate the inside of a building can now claim a 30% investment tax credit on any such project that is under construction by the end of 2019. The credit drops to 26% for projects starting construction in 2020 and 22% in 2021. This is the same phase-out schedule as for solar projects.

Small cogeneration facilities — called "combined heat and power" or CHP projects — will qualify for a 10% investment tax credit if under construction by the end of 2021. Until this change, such projects had to be completed by the end of 2016. The full tax credit can be claimed on projects of up to 15 megawatts. The credit amount phases out as the generating capacity moves from 15 to 50 megawatts.

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were merchant gas?

MR. BOUDRIAS: Most of them were in that category. There was one coal transaction, and there were only three renewables transactions.

MR. MARTIN: Were all of the merchant projects in PJM or ERCOT?

MR. BOUDRIAS: The last ERCOT deal was in early 2015, so almost all of the volumes have been for transactions in PJM, New York and New England.

MR. MARTIN: What do you expect in 2018?

MR. BOUDRIAS: We expect the same as 2017. When one thinks about the source of new transactions in our market, it is refinancing of projects that were not financed originally in the B loan market and financings of new assets that will enter the market via M&A. The M&A market does not have a very strong backlog at the moment, so we may be looking at continued tightening of pricing that may lead to more refinancings of deals that were originally done in bank market as they come into the term loan B market.

MR. MARTIN: Pricing a year ago for strong BB credits was around 350 basis points over LIBOR with a 1% floor and 1% OID. Single B credits were pricing at 425 to 450 basis points over. We heard Ralph Cho say that, in the bank market, quasi-merchant is getting 325 over LIBOR, trending down. I assume the term loan B rates have come down as well. Where are they today?

MR. BOUDRIAS: BB credits are probably 325 over. A number of independent power producers that tend to be treated more like corporates have all repriced in December, taking between 25 and 50 basis points off their spreads.

It is not unforeseeable that the 325 I just gave may be on the high end and that you may see some of the deals that were repriced in the fall come again for potential repricing that may tighten further to the tune of another 25 basis points.

MR. MARTIN: That is 25 basis points improvement over last year, so 325 but trending down.

MR. BOUDRIAS: That's right, and single B is probably the same thing. The right range for single B credits is probably in the 400 to 425 range.

MR. MARTIN: Explain what a B loan is for anyone who is unfamiliar with the term.

MR. BOUDRIAS: It is a loan that is documented the same way as a bank loan, but the lenders are institutional lenders. The biggest difference will be in the amount of refinancing or merchant risk that lenders will be willing to take, and obviously it is a capital markets execution, so the transaction when it is launched generally will get done over a 10-day period, during which the debt participations are allocated and then it trades. For example, a normal $500 million transaction will probably have something like close to 40 lenders. B loans tend to be used in riskier projects like quasi-merchant deals.

MR. MARTIN: Are B loans still for seven years?

MR. BOUDRIAS: Yes.

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

MR. BOUDRIAS: We have not seen new construction in our market for some time. The last new-build deal was in the fall of 2015. Advance rates historically have been close to the mid-60s. Obviously it will depend on a variety of factors. I may have touched on them last year if anyone has access to the February 2017 NewsWire. The US government issued leveraged lending guidelines in 2012 that set a limit on the amount of leverage permitted for most transactions. In general, deals do not exceed six times leverage, require 50% repayment over seven years and have a loan-to-value ratio of 75%. That is what the federal bank regulators are looking for, and that is generally where you see transactions cap out in the institutional market.

MR. MARTIN: Are there any other new trends in the B loan market as we enter 2018?

> A new base erosion and anti-abuse tax — called BEAT — looks likely to affect only a small number of tax equity investors.

MR. BOUDRIAS: Demand for B loans in the power sector has not kept pace with the supply of capital that has been assembled to pursue the opportunity. The volume of power-sector B loans has grown less rapidly than the volume of B loans in the broader economy.

Project Bonds

MR. MARTIN: Let's move to John Anderson and project bonds. The project bond market does not do well when the bank and term loan B markets are wide open and looking for product. Ralph Cho said 70 to 90 banks are now chasing deals. On the other hand, interest rates seem headed up. The yield on 10-year treasuries spiked yesterday at a little over 2.6% before backing off slightly. How many project bond deals were there in 2017, and where do you see the market headed this year?

MR. ANDERSON: The project bond market is long, cheap, fixed-rate money. The long loan tenor is its competitive advantage, and we tend to see people come to this market when they are looking to lock in inexpensive base rates for fear that rates are on the way up. In terms of rates, notwithstanding some of the movement we are seeing this week, the overall cost of capital for project bonds declined last year as did rates in the broader corporate investment-grade market. High-grade fixed-rate credit came in by about 20 basis points year over year last year.

The 10-year treasury has remained flat over the last year at 2.5%, and the 30-year treasury is actually in by 10 basis points from 3% to 2.9%. Put all that together and combine it with increased investor appetite for the asset class, and we have seen spreads on project bonds come in a similar 25-plus basis points year over year as has occurred in the bank and term loan B markets.

MR. MARTIN: What is the current spread above 10-year treasuries?

MR. ANDERSON: We are seeing spreads of 175 to 200 basis points for high-quality US deals, maybe a bit tighter in some cases, and that puts the coupon rate in the 4%-to-5.5% range, with most of it in the 4%-to-4.5% range for clean projects.

There has been a pretty stable flow of projects. We have seen gas-fired units used to back renewables. We have seen wind. We have seen solar.

Of the roughly half a dozen syndicated deals that we saw last year, the large gas units placed well. You have good visibility in the syndicated market for them. Some wind and solar financings are getting done on a syndicated basis. We saw both last year. But some projects, particularly / continued page 10

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COAL PLANT RETIREMENTS may be delayed by the US Department of Energy.

The department is reportedly considering an emergency order to keep certain coal plants owned by First Energy Solutions operating.

Section 202(c) of the Federal Power Act gives the US government authority in time of war or an emergency due to a sudden price increase or shortage of energy to issue orders to keep power plants operating. If an affected party does not agree with an order, DOE can set just and reasonable terms after a hearing held before or after the order is issued. If the order conflicts with existing federal, state or local environmental laws, it will expire within 90 days unless DOE renews the order after consulting with the Environmental Protection Agency.

The terms of any such order could include that the plants must be fully compensated for their operating costs during the emergency, according to Bob Shapiro with Norton Rose Fulbright in Washington.

TWO CLOSELY-WATCHED LAWSUITS are moving forward.

One is an appeal of a decision by the US Court of Federal Claims in late October 2016 that the purchaser of a power project does not have to allocate part of the purchase price to a long-term power purchase agreement if the power contract can only be used to supply electricity from a particular project. The case is *Alta Wind I Owner v. United States*.

The claims court said the contract has no value independently of the power plant. Therefore, any amount paid for the PPA is basis in the power plant and goes into the calculation of tax benefits. (For earlier coverage, see "Treasury Loses Key Case" in the December 2016 *NewsWire*.)

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Cost of Capital

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community solar transactions, are too small for the syndicated or public market and are being done with one investor or in club deals in the private market.

From our own activity and talking to other lenders, we think volume was flat year over year. The cost of capital fell both in terms of base rates and general corporate spreads. New investors came into the market. These are the same themes you heard about the bank and term loan B markets.

If you had 25 or so keen investors a year ago, you probably have 30 today. There has been increased interest from overseas investors. Some such investors have teams in the US. Some are using US advisors to find opportunities for them to lend.

In terms of trends, I agree with Ralph Cho's comment. To clear renewable energy at an attractive return, you have to bid something for the merchant tail.

MR. MARTIN: Meaning to win the deal you have to give some value to the merchant revenue?

MR. ANDERSON: Exactly right. You cannot just count the contracted cash flows and get to something that works. The other thing that is interesting is it felt like 2017 was the year that the market went explicitly no-bid for coal or pretty darn close to that for coal-fired power plants. Granted that no new ones are getting built today, but in terms of secondary sales of project bonds that were already used to finance such plants, it felt like there was a chilling pull-back in terms of investors that were willing to buy such bonds last year.

MR. MARTIN: Very interesting. How many deals are in the pipeline as we start the year?

MR. ANDERSON: Probably about the same as last year. We have about half a dozen between things in the syndicated and club or direct markets that we are looking to work on. Our transactions tend to move quickly, so a point-in-time snapshot of the deal pipeline ends up being not that representative of what happens over the year. In our market, four weeks to place a syndicated transaction is plenty of time. You do not always get much forward visibility on what is coming.

MR. MARTIN: You said there were around six syndicated deals last year. Do you have any feel for the volume of private transactions?

MR. ANDERSON: It is anyone's guess because there is not good data on the private market. In general, you probably have more capital flowing through the syndicated market and less capital through the club market, but probably a higher number of transactions in the club market because they tend to be smaller. ◎

Reading the Current Market

A panel of company CEOs and investors talked at the annual Infocast "projects & money" conference in New Orleans in January about where the opportunities and pitfalls are in the current market and what to expect in the year ahead. The panelists are Paul Segal, CEO of LS Power, Paul Gaynor, CEO of Longroad Energy, Himanshu Saxena, CEO of Starwood Energy Group, Herb Magid, head of Ares EIF, and Grant Davis, managing partner of Infra-Energy Capital Advisors. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

MR. MARTIN: Herb Magid, and then each of you in turn, how would you characterize the current market?

MR. MAGID: It is almost as if someone took all of the pieces of the industry that we knew and threw them against the wall. They are falling together in different patterns. It makes for a very interesting time, but also I think a very nervous time for anyone involved in the business.

MR. DAVIS: It is a seller's market, probably with the exception of greenfield merchant plants in PJM. The wall of capital that continues to chase operating projects is leading to distorted returns.

MR. MARTIN: It is distorting returns downward?

MR. DAVIS: Yes.

MR. GAYNOR: There is a lot of anxiety in the renewables business. The last 90 to 100 days have been spent watching tax reform and the base erosion and anti-abuse tax, or BEAT, and trying to figure out what they will do to the tax equity market. Now we are waiting for the solar tariff shoe to drop. So it has been a period of anxiety for developers, but there is a fair amount of permanent capital and debt capital seeking to invest at the same time in the sector.

MR. SEGAL: In the context of new projects, it is an incredibly difficult time. This has a lot to do with the oversupply of capital. People are so eager to find projects to finance or in which to invest that the returns are extraordinarily low, and financiers are going beyond discounting the known cash flows in their eagerness to find projects. The assumptions bidders are using are incredibly aggressive, and that makes it objectively a very difficult time. The low returns leave people like us frankly with very little to do in terms of new development activity.

MR. SAXENA: The deals we are seeing are moving up the curve in terms of risk. People are having to take more risk to make minimal returns. People who never used to be willing to take development risk are taking development risk today in order to find projects. People who never used to do merchant deals are doing merchant deals. People who said that they would never go into Mexico are now in Mexico. People who have never been to Chile are now in Chile. The oversupply of capital is leading to more risk taking in the market.

MR. MARTIN: Does anybody think that any type of capital is in scarce supply?

MR. GAYNOR: Early-stage development capital is not nearly as easy to find as later-stage equity or debt.

MR. MARTIN: Development capital has always been hard to find. Is it any harder to find today than in the past?

MR. GAYNOR: No. It is easier to find today, but remains relatively scarce given the larger wall of capital chasing deals. There is no wall of early-stage development capital. We just raised a bunch of development capital. We have a good track record of delivering on projects. It was bloody hard.

MR. MARTIN: Himanshu Saxena, how do you square what Paul Gaynor just said with your comment that financiers are having to take greater risk to deploy capital?

MR. SAXENA: It depends on the asset class. Finding development capital for a transmission project is nearly impossible. Any project that will take five to 10 years to build is very hard to fund in the development stage. There is more early-stage capital for solar projects that take six to 12 months to develop.

MR. MARTIN: Herb Magid, are you more willing today than you were in the past to fund development efforts?

MR. MAGID: We have always funded development, but I agree with Himanshu that it is difficult to put a lot of money out the door in development-stage projects, so of necessity, most of the capital gets invested at a later stage.

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The US government appealed. Oral arguments were heard on January 12 in the US appeals court for the federal circuit in Washington. A decision is expected later this year.

The other case is a test of whether developer fees paid under a development services agreement by a project company to the developer go into basis in the project.

The case has been set for trial in the US claims court starting on July 23.

A project company paid the developer a developer fee of $50 million, or 12.3% of the project cost, on a wind farm in Illinois and put the amount in basis for a Treasury cash grant. The Treasury paid the developer $9.2 million less in Treasury cash grant proceeds than the developer thought it was entitled to receive. The developer sued for the difference. The Treasury filed a counterclaim asserting that it overpaid the developer by $5.2 million.

The government says the developer fee should not count toward the cash grant because it is circled cash: the developer made a capital contribution to the project company to pay itself the fee. The government also argues that the fee is not a real "fee" because it was a function of what the developer could have earned on a sale of the project rather than the actual services performed.

In late December, the court declined to decide the case at "summary judgment," meaning solely on the basis of legal briefs filed by the parties, and ordered a trial.

The court said "the record contains suggestions that a markup or premium or profit may be appropriate in certain circumstances when considering total costs." Whether such a fee is appropriate in this case, and how much, will turn on the facts.

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MR. MARTIN: Why are projects in such scarce supply?

MR. SAXENA: One reason is the difficulty finding long-term buyers for electricity. It still used to be possible five years ago to enter into long-term power purchase agreements from gas plants. We don't see any buyers today for electricity from new gas-fired power plants. Consequently, there has been no recent new construction of gas projects other than in PJM with heat-rate call options. Even that activity has dwindled in the last 12 to 18 months.

Corporate buyers have taken up part of the slack, but the number of corporate PPAs is not huge. Most markets are oversupplied. New power plants are not needed in most parts of the United States. Some projects that are being built are built unnaturally in the sense that these markets do not need the additional electricity. Developers rely on retirement forecasts to create opportunity. That's why projects are scarce. I suspect things may remain slow in 2018 for new-build gas activity.

Opportunities?

MR. MARTIN: Where are there opportunities, if any, starting with Paul Segal?

MR. SEGAL: Adding first to what Himanshu said, the utilities invested a lot over the last 10 to 15 years in transmission and distribution, but very little in new generation. Now some of them think they are missing an opportunity. An increasing share of renewables projects are ending up in utility rate bases either because the utilities are building them or asking for build-own-transfer bids in place of signing more traditional power contracts. That is taking the opportunities away from the community in this room.

In terms of where we see opportunity, I think the opportunity this year is to spend a good amount of time on the beach for anyone thinking about new power plant development. We are spending our time in the secondary market, essentially buying projects or portfolios of projects that are 15 to 20 years old, often from private equity funds.

MR. MARTIN: What type of assets?

MR. SEGAL: Mostly gas fired.

MR. MARTIN: What discount rate must one use to win such bids?

MR. SEGAL: This becomes much more a question of assumptions than discount rates. We seek very high returns for those investments, but the assumptions we make in terms of what we will be able to do with the assets and what will happen in the market will drive the ultimate internal rate of return. It is less a matter of cost of capital and more what we can do with the individual assets over a short period of time.

We are also spending a lot of time on transmission development opportunities. This has proven to be a very difficult, but very rewarding game. Very few projects are being awarded in the competitive transmission sphere. We are hoping that the regulators see the benefits of competition and open up more opportunities to competitive bids. There is a genuine consumer benefit when projects are put out to bid for interesting new ideas and risk transfer.

MR. GAYNOR: We are spending most of our time on utility-scale wind and solar projects, especially solar in places like Texas, Colorado and southern PJM.

MR. MARTIN: You told me in an airport last fall that the competition for power contracts is "brutal." Are these merchant projects?

MR. GAYNOR: The beauty of solar compared to wind is you do not have to put as many dollars out the door ahead of getting a PPA. That allows you to place a lot of different bets at the same time. Once we secure a PPA, then we can move into spending more significant development capital.

The other place we are spending time is on fixer uppers. They are either good assets that are in the wrong hands or assets that need to be restructured because, for example, the tax equity is under water. We have a pretty

It is almost as if someone took all the pieces of the industry that we knew and threw them against a wall.

healthy effort underway on the repowering front. We take a wind project that has reached the end of the tax credit period, put on repower kits and capitalize the project.

MR. MARTIN: Grant Davis, name one opportunity that you would be pursuing if you were still at Tenaska.

MR. DAVIS: A key area of focus for the institutional investors I work with is selected M&A around gas-fired power plants and, outside of power, midstream storage.

MR. MARTIN: Herb Magid, one opportunity.

MR. MAGID: The window for development and construction of new gas plants is pretty well closed at the moment, but there are opportunities in the secondary market where we have been both a buyer and a seller. It is a very, very weak market for buying assets. The winner is the guy who can see an asset and not beat up on it much during diligence.

MR. MARTIN: Not see the risks that others might see.

MR. MAGID: The way to win is to take a view on a particular market or particular asset and go proactively to the owner and say, "We see some value here," or participate in a way where you are taking some extra risk, but it is a risk you understand. It is a much more difficult market, but three are still plenty of opportunities if you are careful about assumptions.

MR. MARTIN: Himanshu Saxena, one opportunity.

MR. SAXENA: We build a lot of renewables. We buy gas. We build transmission. We expect in 2018 to do more renewable energy projects with corporate PPAs. We just signed a long-term PPA with General Motors for a wind farm we are building in Ohio. We get calls from corporations that are interested in buying renewable energy. Everything else seems fairly saturated.

Potential Inflection Points

MR. MARTIN: Let me throw out a series of questions without directing them to any one person. Where do you see potential inflection points in the next few years?

MR. GAYNOR: We have heard numbers as high as 50,000 megawatts of wind farms can be built between now and the end of 2020 and qualify for tax credits at the full rate using equipment stockpiled in 2016. One potential inflection point is what happens after 2020 and who is left holding the bag with all of this equipment to the extent it does not get fully deployed.

If production tax credits disappear for wind, what will power buyers do? Will they be willing after 2020 to start paying more for power? Will true equity and tax equity investors be willing to earn less to make the deals work? Will turbine vendors cut their prices enough to make the deals work?

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In an earlier skirmish, the developer, Invenergy, tried to get the court to order the US Treasury to reveal data about the developer fees it accepted on 108 other wind farms. The court declined on grounds that such information "has generally been considered irrelevant." The case is *California Ridge Energy LLC v. US*. A companion case that will be heard at the same time involving a second wind farm with the same issues is called *Bishop Hill Energy LLC v. US*. (For earlier coverage, see "Treasury Cash Grant Update" in the February 2016 *NewsWire*.)

A third Treasury cash grant case that revolves around when two biomass power plants were placed in service is headed to trial on May 14.

The biomass case could also raise issues about how to apply a so-called 80-20 test for determining whether a power plant was so extensively rebuilt as to be considered a different facility.

The owner says the two plants were not in service as early as when the Treasury believes. The Treasury believes they were in service in 2008, which would have been too early to qualify for a Treasury cash grant. The program did not start until 2009.

The plants — in Chowchilla and Merced, California — were originally built in the late 1980s, but shut down in 1995 and then restarted in 2008. Soon after they restarted, the San Joaquin Valley Unified Air Pollution Control District and the US Environmental Protection Agency issued notices for violation of permits. Both facilities stopped operating in 2010.

The current owner bought both plants in 2010 and spent money on improvements. The prior owner claimed production tax credits on the electricity output during the period 2008 through 2010.

The current owner applied for cash grants of \$12.3 million on each plant. The Treasury paid \$1.13 million on each.

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All of that will be pretty interesting.

MR. MARTIN: Does anyone see other potential inflection points?

MR. MAGID: I expect a pretty dramatic pullback in five years from investing in renewables. People who want renewables will have them in their portfolios by then. Others will have bid too much for them in the current market and realize that they made lousy investments. The same thing will happen that we are seeing today in PJM capacity. The pack will move to another flavor of the month. I do not see renewables remaining a frothy market in the long term. The sovereign wealth funds and pension funds will have something for their annual reports and then move to the next big thing.

MR. MARTIN: Paul Gaynor, that's your livelihood.

MR. GAYNOR: He may be right. People said that about the wind industry in 2003. There are always winners and losers in each of these markets. When do you get in? When do you get out? What is your investment horizon? These are never easy questions to answer. To me, that sounds like a great opportunity for someone like us.

MR. SAXENA: The renewables market has been one where you can build an asset with a contract and sell it to a six-percent buyer. You can play that game all day long.

To my mind, the inflection point is a future shift in the debt market. There are a lot of large asset portfolios trading. We did a term loan B financing in early December that was 3.5 times overbid. There is so much liquidity in the debt markets. When it stops, the asset values will start to drop, and I think that is a serious risk.

MR. MARTIN: Congress enacted a $1.5 trillion tax cut at the end of the year. What effect do you expect this to have on your businesses?

MR. SAXENA: Not much for us because I think tax equity remains plentiful and tax equity yields continue to fall. We are seeing deals this year with better pricing than in December. As long as tax equity is alive and kicking, renewables will live. We are not seeing any effect in other parts of our business.

MR. DAVIS: The biggest hope for an impact would be an acceleration in economic growth. One of the big weaknesses in the power sector is lagging demand for electricity. It would help if the economy would grow faster.

Storage

MR. MARTIN: This is a market with a lot of strong cross currents. Many people believe storage is certain to replace gas peakers because it can perform the same task more cheaply. Do you share that view?

MR. GAYNOR: It depends on the part of the country. We built two large utility-scale batteries to support our wind farms in Hawaii. The batteries were very expensive, but they made sense in Hawaii. They make sense in California. They probably do not make sense in places like ERCOT.

MR. MARTIN: Why?

MR. GAYNOR: Because there is enough resiliency and the grid will not pay for the quick response. You do not need it unless you are way out at the end of a line or something like that. We are working on one deal where the utility is telling us it will do solar, but the solar has to come with storage. To Herb's point, the utility's position may be more philosophically-driven than technically driven.

MR. DAVIS: Storage is a little bit like bitcoin. You can't go to a cocktail party without people asking what you think about bitcoin. You can't go to a power conference without people asking what you think about storage. Everybody would like to be ahead of the curve as storage matures, but from an investment perspective, we are probably 10 years away from it becoming broadly economic and there will probably be a technology switch in the middle of that period.

MR. MARTIN: Gabriel Alonso, who was CEO of EDP Renewables North America, said that when PPAs are being signed to supply electricity at 1.6¢ to 1.8¢ a kilowatt hour, the ability to earn another penny a kilowatt hour by providing ancillary services from a storage facility starts to look attractive.

Where do you see current opportunities, if any, to add storage aside from Hawaii and California?

MR. MAGID: The industry is transforming so fast that it would not surprise me to see storage take hold more quickly than anyone expects today.

Society wants it. You go to battery storage conferences and see there are a lot of companies working on better batteries. It is just a matter of time before we start to see major breakthroughs. I think we will see it take hold first with distributed generation as a way of offering more reliable service.

MR. MARTIN: Does anyone see current opportunities for storage besides Hawaii and California?

MR. SAXENA: We made an investment in a battery storage developer in California who is installing batteries in places like Home Depot retail warehouses. This goes to Herb's point that there is still a lot of opportunity in places like California to install batteries behind the meter.

MR. MARTIN: Paul Gaynor, when you reinvented yourself as Longroad Energy Partners, you shifted from all wind to about 30% wind and 70% solar. Why keep a foot in both camps? Why not go all solar?

MR. GAYNOR: I think you have to offer both technologies to succeed in the current market, depending on the part of the country. In PJM, there is demand from the corporate sector, mostly data centers, for 10-year PPAs. If you think about developing solar versus developing wind in PJM, wind is multiples harder on a degree of difficulty, so you have to have the ability to do solar in that case. In MISO and in parts of Texas, wind will be more competitive. It is just a matter of having a full toolbox.

MR. MARTIN: Paul Segal, LS Power has put substantial resources into transmission. How long does it take to finish such a project, and why move into a regulated business?

MR. SEGAL: Getting one of these projects awarded is difficult. The awards process can take a year to three years. What we like about the business is there is a high barrier to entry. The ISOs and utilities want to see a high level of competence and experience. Transmission is much harder than developing most forms of generation opportunities. When we get awarded a long duration rate-regulated rate of return, that is obviously a highly financeable, very durable stream of cash flow.

MR. MARTIN: Herb Magid, you put a lot of effort into transmission over many years. What lessons did you take away from the experience?

MR. MAGID: They are great assets once you get them. The issues are how long they take to develop and how much money you want to put into them. They are riskier than power plants. You are developing something that runs hundreds of miles and will face unrelenting environmental opposition.

MR. MARTIN: So the lesson is you have to be patient, it is better to put your money elsewhere or what?

MR. MAGID: The lesson is that you really have to go in with someone who has done it before. It is easy to underestimate how hard it is.

MR. MARTIN: Himanshu Saxena, Starwood appears to have focused in the last two years on wind and gas-fired generation. Will that remain your focus in 2018?

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Meanwhile, a solar developer filed suit in the US claims court at the end of January seeking an additional section 1603 payment on the McCoy solar project, a 250-MW solar thermal project in California that was put in service in 11 phases. Separate grant applications were submitted on each phase over the period October 2015 through June 2016. The cumulative grant received was about $11 million short of the amount the owner expected.

The issues in the case center around whether particular spending belongs in basis in the power plant as opposed to some other asset. The cash grant is calculated only on the basis in the power plant.

The Treasury decided that a $4.3 million fee the project paid to the California Department of Fish and Wildlife, in place of buying land as a mitigation measure for potential harm to the desert tortoise and burrowing owl, did not belong in the power plant basis. It had the same issue with another $712,500 the project spent on mitigation land to compensate for harm to the Mojave fringe-toed lizard.

The Treasury reduced the basis in the power plant by another $32.7 million that it said is not a cost of the McCoy power plant. Eight months after the McCoy project company signed a construction contract to have First Solar build the project, Silver State, another project under common control with McCoy, signed its own construction contract with First Solar for a contract price that could be reduced if the McCoy project met specified progress targets. The final amount payable by Silver State to First Solar was $32.7 million less than the maximum amount First Solar could have earned on the Silver State contract.

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MR. SAXENA: Wind, gas and transmission will remain our three areas of focus in 2018. We made our first coal investment recently, so we are starting to look as well at assets that are currently out of fashion.

We are surrounded by new disruptive business models. That is the challenge and also the opportunity.

Going Merchant

MR. MARTIN: The US added 25,000 megawatts of new generating capacity last year. It is hard, as Paul Gaynor said, to find utilities willing to sign long-term PPAs. Corporate PPAs are substituting for them, but only around 2,850 megawatts of corporate PPAs were signed last year. Paul Segal, how does the independent power business thrive in such a market?

MR. SEGAL: Our market has evolved as capital has become more freely available. I imagine the vast majority of new capacity additions were gas-fired generation that is being built on short-duration price signals. Short-duration capacity clears and has probably inflated energy margins in places on the grid where gas is constrained. Investors are making assumptions that these conditions will persist at the same time that significant investment is being made to relieve gas constraints.

I think a more realistic point of view will emerge as to the likely profitability of new investment in truly merchant power projects. We all need to adjust to the idea that there is less to do in an environment where demand growth, except for perhaps around the Gulf Coast, is muted or even non-existent.

MR. MARTIN: How hard is it to arrange a hedge today in places like ERCOT, PJM or ISO-New England?

MR SAXENA: It is very easy, but you may not like the price.

MR. GAYNOR: It is easy on one level, but it is expensive from a developer's point of view. It takes a lot of time to get there, and usually you have to commit big dollars before what a developer would consider a comfortable commitment point. Most hedge providers have limited bandwidth. They often staple the hedge to a tax equity investment.

MR. MARTIN: They will not provide the hedge without also acting as the tax equity.

MR. GAYNOR: There are many of those institutions that will not do one without the other. It is hard to run a true competition in such a market. That is where Himanshu is right. You might not like the price ultimately on offer. It is a white-knuckle ride where you are praying that gas prices stay at a certain level the day that you are ready to close.

MR. MARTIN: Do you expect to see a hedge this year on a utility-scale solar project, and why have we not seen one so far?

MR. GAYNOR: Yes, you will see one.

MR. MARTIN: Why have we not seen one so far?

MR. GAYNOR: I don't know. My sense is that most people are waiting for the Suniva tariff decision.

MR. MARTIN: What hard-won lessons have any of you learned from your exposure to quasi-merchant or hedged projects?

MR. SAXENA: Location really matters. In certain parts of the Texas panhandle, for example, you are seeing basis risk of $10, $12 or $14 a megawatt hour, and those projects are getting destroyed.

MR. MARTIN: The basis risk of $12 to $14 a megawatt hour is the exposure to the generator?

MR. SAXENA: Correct. The spread is very wide, and it is killing the projects. If you are making $20 on the hedge and you have a $14 negative basis, your take-home money is $6, and that is not enough to cover your costs in most cases.

MR. MARTIN: John Eber from J.P.Morgan argued on a cost-of-capital call last week that the market is underestimating the basis risk in projects with hedges or virtual power contracts. Basis risk is the difference in pricing between the hub and the bus bar for the project to which the generator is exposed under most contracts. How big a risk is this in your minds, and how are people covering it?

MR. GAYNOR: It is among the top three risk items that we look at before we pursue or spend any significant development dollars. It is at the top of the list.

MR. MARTIN: What are your other two?

MR. GAYNOR: The quality of the solar or wind resource and land. How hard will it be to get land control? For example, does someone else own subsurface mineral rights?

Bid Stresses

MR. MARTIN: I have two more questions before turning it over to the audience. Paul Segal said the competition for assets does not turn on who has the cheapest cost of capital, but rather on who is willing to make the most aggressive assumptions. Do the rest of you agree?

MR. SAXENA: Yes. If you are bidding on a gas-fired power plant in PJM and you have a consultant curve that shows $350 a megawatt day in 15 years and you believe that curve, your cost of capital can be 30% and you will still win the auction. On the other hand, you could say the market flattens out at $100 and your cost of capital could be 8% and you will not win. The cost of capital alone is a meaningless number.

MR. MAGID: It is also the quality of the bidder. There are lots of people that throw in bids from one auction to the next to have an oar in the water, but without being serious bidders. The auction process is breaking down. There are more opportunities today for a buyer and seller to get together directly.

MR. MARTIN: Who has the cheapest cost of capital in the current market?

MR. DAVIS: Asian investors and some of the infrastructure funds.

MR. MARTIN: Let's leave room for a few audience questions. Buz Barclay from Rimon.

MR. BARCLAY: It is a tough market. Are you seeing equipment vendors stepping up to help with pricing?

MR. SAXENA: We are seeing a lot of constructive financing from large OEMs. One of them is putting its profit from the turbine sale back into the project as preferred equity. This particular vendor has done this consistently in the last 10 deals it has done. The turbine suppliers are eager to find creative ways to make your projects work. They cannot sell their turbines fast enough.

MR. EISENSTAT: Larry Eisenstat from Crowell & Moring. This is a question for Paul Segal. Do you see storage as a means to defer or possibly avoid having to build transmission?

MR. SEGAL: Every situation obviously / continued page 18

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Finally, in a harsh result, the government won a summary judgment (on the basis of legal briefs rather than a trial) against WestRock, a paper company, that was seeking an additional section 1603 payment on a biomass power plant it completed in 2013 in Covington, Virginia to supply steam and electricity to a paper mill.

The Treasury's position is that any power plant that produces both steam and electricity must allocate the cost between the two functions. A grant is paid only on the electric generating equipment.

Two other cases have upheld this principle. (See discussion of *W.E. Partners* in "Treasury Cash Grants" in the February 2013 *NewsWire* and February 2015 *NewsWire* and of *GUSC Energy* in "Treasury Loses Key Case" in the December 2016 *NewsWire*.)

WestRock applied in December 2013 for a grant of $85.9 million. Treasury paid only $38.9 million, after concluding that only 49.1% of the plant costs were tied to electricity production as opposed to steam. It reduced the basis by another 0.22% because the plant uses fossil fuel for startup and flame stabilization.

WestRock offered five approaches for allocating costs between steam and electricity. The court said the company had the burden of proof to show its method was better than the method used by the Treasury. It found none of the WestRock proposals compelling and decided the case for the government. The case is *WestRock Virginia Corp. v. United States*. The court released its decision in early February.

The day before the decision was released, Nippon Paper Industries USA Co., Ltd. agreed to a dismissal of its case involving a grant paid on a biomass power plant at a paper mill in Port Angeles, Washington. The Treasury paid a grant on 82.8% of the project cost after allocating part of the cost to steam put to industrial use.

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is specific, but we are seeing a number of situations across the country where storage is being considered as an alternative to transmission investment that may have been triggered by other asset retirements and reliability concerns. I think it will be a tool in the tool kit for transmission owners and potentially independent developers playing on the transmission side.

The key to maintaining functional markets is to ensure the asset is used in a way that does not interfere materially with truly competitive markets to the extent the asset sits within competitive markets. We are going to see utilities, as they have with wind and solar, look at storage as an opportunity to deploy capital.

Elusive Profits

MS. BARROW: Deanne Barrow with Norton Rose Fulbright. Paul Segal, you said that when buying assets, it is not about discount rates, it is about assumptions. So my question is, for utility-scale solar, to what extent are valuations being driven by extending the life of the asset, and what are you seeing as typical assumed lives?

MR. SEGAL: We developed several solar projects in the late 2000s and financed them early in this decade. Those were projects that had significant profitability, and there was really no discussion about value beyond the PPA life. That is where we started.

Several years later, there was still an opportunity to get a low- to mid-single digit return during the PPA life relying on actual expected operations versus what might be on a piece of paper.

Lately, we have seen very little opportunity to do more than recover our investment during the life of the PPA, and all of our return on investment, return on equity, would need to come from assumptions that we would make, or that an investor would need to make, for the period after the PPA.

That has not been a very attractive opportunity from our perspective. Nevertheless, we are seeing an enormous number of projects, maybe fewer than have been happening over the last few years, continue to get financed.

MR. MARTIN: Two final questions. The *Financial Times* reported in December about two companies that added blockchain to their names. One was a Long Island Iced Tea, a soft drink maker, that added blockchain to its name and saw its share price shoot up 500% in one day. Rich Cigars saw a 2,000% increase in one day after refocusing its business model on blockchain.

There have been some multimillion dollar initial coin offerings where virtual platforms for electricity sell tokens that are a cost of entry, like a subway token to come onto the platform, to buy electricity. Does this suggest that there might be another possible outlet in the not-too-distant future for some of the power from your projects?

MR. SAXENA: I have seen reports that cryptocurrency mining would take more energy than electric vehicles in the future.

MR. MARTIN: Not just that, but GTM reported that China, which does most of the bitcoin mining, will use as much electricity by 2020 as the entire globe does currently.

MR. SAXENA: A hedge fund that is the largest shareholder in Atlantic Power is urging the company to use its surplus electricity for bitcoin mining. The response by the company is the same response that I would have given, which is this is very, very new. You do not know what the credit would be on the other side. If bitcoin mining turns out to be a viable buyer base, then by all means. It is the same thing as selling electricity to data centers. The market is evolving. Will independent generators be selling electricity directly to cryptocurrency miners in the next five years? I just don't know.

MR. GAYNOR: Cryptocurrency mining is still a little too opaque to generators like me. It still sounds like a really long putt to be able to persuade lenders and tax equity investors of the stability of the potential revenue stream. I am not sure why a generator would spend a lot of time on it until some of these fundamental issues are sorted out.

MR. SEGAL: Usually when something does not make a lot of sense, it does not work, and I would throw this one into that category. I wish them luck. When you look at the economic cost of providing all of this energy to this outlet, is there an offsetting or commensurate economic gain? I don't see it.

MR. MARTIN: Last question. Does any of you see any other potentially disruptive business models or technologies currently in the market or on the horizon?

MR. SEGAL: We are surrounded by them: batteries, distributed generation, micro-grids, LEDs, community solar, energy efficiency. This is part of why we are here talking about an unclear path forward for our industry. We are surrounded by disruptive technology and disruptive events. That is the challenge and potentially also the opportunity. ◎

New Technologies and Old Issues Under PURPA

by Robert Mudge, Metin Celebi, Marc Chupka and Peter Cahill, with The Brattle Group in Washington and Boston

After nearly 40 years with wide-ranging effects on the US electric utility industry, the Public Utilities Regulatory Policies Act — called "PURPA" — has resurfaced as a prime mover for renewables development in some parts of the country.

This has refocused stakeholders on historically contentious features of the law that have been amplified under recent market conditions.

PURPA has required utilities since 1978 to purchase power from small independent electricity generators at the "avoided cost" the utility would spend to generate the electricity itself. Utility avoided costs are typically based on fossil fuel technologies.

For much of its history, PURPA has been largely insignificant for renewables, which have not been viable at avoided cost pricing (even with tax incentives). For that reason, renewables have mostly been developed under renewable portfolio standard or "RPS" regimes, with renewable energy credits or "RECs" as further uplift on the value of their output. However, the US Energy Information Administration reports that the levelized cost of renewables will soon trend below avoided costs nationally. The cost convergence is more dramatic in regions with high renewable resources. Renewables developers are thus flocking to establish projects as qualifying facilities or "QFs" under PURPA and to enter into avoided cost power purchase agreements, where such contracts are available.

Burgeoning Renewables

Virtually all net growth in QF generating capacity over the last 10 years has come from renewables (per a Brattle compilation of public data).

Net growth in QF generating capacity over the last five years has come principally from solar. Renewable QFs have comprised about 16% of total wind and solar development over that time.

The entry of renewable QFs has been concentrated in states where PURPA continues fully in force, meaning states not served by competitive wholesale electricity markets. Renewable QFs have come on line even in states with alternative incentive mechanisms, such as RPS regimes. In

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When it filed suit, Nippon said it was aware of seven other biomass power plants that received full grants on similar facts. (For earlier coverage, see "Treasury Cash Grant Update" in the February 2016 *NewsWire*.) The case has been withdrawn "with prejudice," meaning it cannot be refiled.

H-S-R FILING THRESHOLDS will go up at the end of February.

The new thresholds will apply to company and asset sales that close after February 28, 2018, according to Daniel Wellington and Luke McFarland with Norton Rose Fulbright in Washington.

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

Transactions valued at more than $84.4 million may now trigger H-S-R reporting requirements. There is no H-S-R reporting for any transaction valued at $84.4 million or less, regardless of the percentage of assets or voting securities being acquired.

Under a size-of-person test, when the value of a proposed transaction exceeds $84.4 million, but is less than $337.6 million, then the transaction must be reported if one party to the transaction has total assets or net sales of at least $168.8 million and the other party has total assets or net sales of at least $16.9 million.

All transactions valued at more than $337.6 million must be reported.

Filing fees have also been adjusted and run $45,000, $125,000 or $280,000, depending on the size of the transaction and percentage of voting securities involved in the sale.

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some cases, this reflects RPS targets that have already been met and thus generate low REC prices. However, even in states where RPS targets remain to be achieved, renewable QFs may still make economic sense, particularly where avoided-cost contracts are more attractive than PPAs won in competition with other lower-cost renewables.

Renewables' increasing competitiveness has led to perceived oversaturation of renewable QFs in certain utility systems. For example, new QFs constitute 18% of the total current capacity in North Carolina, 26% in Utah, and 24% in Montana.

The concerns include disruption from stepped up volumes of intermittent resources, requirements for new transmission lines and other upgrades, and over-supply of electricity priced at avoided cost formulations higher than market prices. Not least among the utility concerns is that under current conditions of low load growth, new QFs may now be displacing existing assets (by contrast to the original premise of avoided costs).

Old Issues are Amplified

Recent developments echo perennial debates over PURPA since its inception.

Project developers, purchasing utilities and regulators have negotiated hard over numerous interactive issues. Key among these are 1) QF eligibility criteria, 2) defining avoided costs and 3) equitable PPA terms. As renewable QFs have become more cost competitive, these issues have only become more acute.

Starting with QF eligibility, importantly, QF PPAs are not bound by any "rationing" based on utility demand requirements, but instead by willingness to supply at the stated avoided-cost price.

Over-subscription could be a problem, long before renewables became as competitive as they are today, such as the case of "standard offer 4" contracts in California in the 1980s. As a potential bounding mechanism, states began to experiment with competitive bidding for QFs in the 1990s. Such auctions were superseded by the development of wholesale markets for energy and capacity, which created alternative outlets for generators previously confined to PURPA.

While it may have been manageable to have QFs rationed by price alone when QFs bore some resemblance to utility-avoided generation, this delicate balance has now been disrupted by lower-cost renewable QFs. This has drawn much attention to parsing eligibility criteria, including project size, technology and development status. Competitive bidding is coming into vogue again.

The levelized cost of solar electricity has been falling by 17% a year.

How to define avoided cost has been a perennial problem. The regulators have struggled with administrative methods of estimating and setting long-term avoided costs, which inevitably stray from actual market costs. While these differentials were originally expected to offset each other over time, in practice, actual costs have continually (and dramatically) dropped below long-term avoided costs estimates.

Avoided costs have never been straightforward to calculate, but recent changes in market conditions and the regulatory landscape have made long-run avoided costs much more difficult to compute with an appropriate degree of precision or confidence. Variables such as projected fuel prices, outlooks for peak-demand growth, retirement of existing resources, and future prices for alternative market purchases all factor into complete avoided-cost estimation. These parameters are becoming less certain in an industry evolving toward intermittent and distributed resources, accompanied by new technologies such as storage, and changing regulatory paradigms.

The rapid penetration of renewable QFs themselves makes both the avoided energy and capacity value much more difficult to forecast. These resources shift the supply curve to the right, reducing marginal energy costs. At the same time, while they provide some capacity benefit to the extent available on system peak, they also tend to create a wealth of reserves on the system and they eventually can push the system peak out to hours when they cannot perform. Thus, their long-term avoided costs are anything but static or stable.

How to reach equitable PPA terms is another challenge. In the realm of PPAs, FERC has historically interpreted PURPA to require some degree of "certainty with regard to return on investment" in QFs and thus that PPAs "should be long enough to allow QFs reasonable opportunities to attract capital from potential investors."

FERC has not translated this statutory goal into a specific number of years. In the early implementation of PURPA, it could mean as long as life-of-asset, but that was clearly more than was needed to support financing. It also meant that QF generators often bore little risk despite participating in competitive markets, and they were not dispatched efficiently in relation to other generation sources.

Today, PPA terms form an ever more contested issue. Utilities may seek short-term PPAs pending fixes to the more fundamental issues of QF eligibility and avoided costs. Also, contractual terms sufficient to attract capital have a different profile for renewables than for fossil-fuel QFs. Not least, they are more sensitive to recent events such as passage of the new tax law in 2017 and the imposition of tariffs on imported solar panels.

Basic Concepts

PURPA was enacted at a time of heavy reliance on imported fuels, high load growth, and utility dominance of the electric power industry. Accordingly, its original mission was to promote energy conservation and encourage deployment of eligible small generators as alternatives to utility resources, where small generators were cost effective.

Among other obligations, the original law and the subsequent FERC regulations required all electric utilities to purchase power produced by QFs at the utility's full avoided cost of energy and capacity. A QF can be either a cogeneration facility (with no size limit) or a "small power production facility" (with an 80-MW size limit) using biomass, waste, wind, solar or hydro to produce power.

PURPA aims to encourage the development of QFs through the must-purchase requirement for utilities. Among other things, the law provides that QFs have the option to "provide energy or capacity pursuant to a legally enforceable obligation" of the purchasing utility.

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THE SOLAR CONSTRUCTION-START RULES are "actively being worked on," according to Hannah Hawkins, the lawyer for energy tax issues in the office of tax policy at the US Treasury.

Hawkins made the statement at an American Bar Association tax section meeting in San Diego in early February. The topic remains on a revised priority guidance plan that the Internal Revenue Service released in the wake of the new tax law showing guidance that the agency hopes to release by June 30.

Some tax counsel are advising solar companies to have construction of remaining solar projects as far along as possible by the end of 2019 because of uncertainty about what must done on such projects to be considered under construction in time to qualify for a 30% investment tax credit. A 30% tax credit can be claimed on any solar project that was under construction by the end of 2019. The credit amount drops to 26% for projects that start construction in 2020 and to 22% in 2021.

However, most counsel expect the government to apply the same principles to solar that apply to wind farms, with some variations to address issues that are unique to solar. Wind farms are considered under construction for tax purposes once the developer has incurred at least 5% of the total project cost or started physical work of a significant nature at the project site or at a factory on equipment for the project.

CORPORATE PPAS are on the increase again.

The Rocky Mountain Institute reports that 2,850 megawatts of power purchase agreements were signed with corporate buyers through December 5, 2017, up from 1,610 megawatts in 2016, but down from 3,260 megawatts in 2015.

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The mandate to purchase energy and capacity offered by QFs is coupled with the requirement that purchase prices reflect the utility's avoided cost, meaning the "incremental cost to the utility of alternative electric energy," or "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."

By definition, determining avoided cost requires conducting a but-for assessment.

A variety of methodologies have been adopted over the years.

In its simplest form, avoided cost has been determined assuming that a QF displaces the utility's next planned generating unit (the "proxy unit" approach).

A more sophisticated approach assumes that instead of displacing a particular generating unit, a QF allows the utility to reduce the marginal generation on its system at any given time, saving the cost of building a combustion turbine of the same size as the QF (the "peaker" approach).

The most elaborate approach (the "differential revenue requirement" method) consists of modeling two system-wide scenarios, with and without the QF in question. The difference in revenue requirement is then attributed to the QF's avoided cost.

Avoided costs have also been determined with reference to fuel indices and, sparingly, in competitive auction processes.

Typically, at the time of instituting PURPA, marginal generation probably would have been defined based on a small combustion turbine similar to most PURPA plants themselves. Therefore, PURPA and the subsequent FERC regulations essentially aimed to ensure a level playing field, enabling the QFs to sell their power to a utility at prices reflecting the utility's incremental cost of procuring the same power from owned or purchased generation.

In PURPA's first incarnation through 2005, QF installations grew by more than 8% a year, largely dominated by fossil cogeneration technologies.

The Energy Policy Act of 2005 modified the must-purchase obligation to exempt utilities from entering into new contracts with QFs that have nondiscriminatory access to competitive markets (mainly regions covered by regional transmission organizations, or RTOs) to sell their power. FERC later created a rebuttable presumption in its Order No. 688 that QFs larger than 20 MW have non-discriminatory access to the markets operated by five RTOs: PJM, Midwest ISO, ISO-New England, NYISO and ERCOT. With respect to CAISO and SPP, FERC indicated that these markets did not satisfy all requirements to qualify as providing non-discriminatory access to independent generators since they did not have day-ahead markets as of the time that Order No. 688 was issued. Now both CAISO and SPP are operating day-ahead markets, and hence may qualify as providing fully non-discriminatory access. Therefore, unless determined otherwise, the utilities' must-purchase obligation has been limited in the RTO regions to smaller QFs of up to 20 MW.

Notwithstanding that PURPA continued to operate per its original terms in non-RTO regions, growth in new QF installations was sharply curtailed after 2005, to less than 1% annually through 2010. Since then, power markets have undergone dramatic changes. In particular, the cost of solar and wind resources has declined toward levels competitive with fossil-fuel generation, leading to renewed growth in renewable QFs after 2010.

Renewables Demographics

Improvements in renewable costs and performance have been dramatic in recent years, for solar in particular. This is, of course, concentrated in regions with abundant renewable resources.

However, even on a national basis, EIA recently forecast the levelized cost of energy or LCOE for photovoltaic solar (including subsidies) as declining at a pace of approximately 17% per year, to achieve parity with the corresponding levelized avoided costs of energy or LACE by 2022.

For the WECC, SPP and SERC regions, EIA forecast a solar LCOE

This is contributing to renewed interest in use of a 1978 federal law called PURPA to land power contracts with utilities.

of $5 to $10 a megawatt hour below the corresponding LACE by 2022.

EIA forecasts a similar pattern for wind, with an LCOE $5 to $15 a megawatt hour below LACE in WECC, SPP and MRO by 2022. If anything, EIA's outlook is conservative, and PPA rates are being reported at even lower levels.

As of July 2017, the total inventory of existing QFs in the US was approximately 90,000 megawatts, 70,000 megawatts of which remained thermal generation. The 20,000 megawatts of existing renewable QFs largely came on line in the last 10 years.

Roughly 24,000 megawatts of QFs are under development, predominantly solar, in non-RTO regions where PURPA continues in force. These projects are largely concentrated in several states. North Carolina (5,900 MW) and South Carolina (2,300 MW) lead the pack, followed by the western states of Utah (2,400 MW), Oregon (2,900 MW), Colorado (1,400 MW) and Montana (1,500 MW). This geographic concentration is additionally driven by a combination of favorable project economics (costs relative to the avoided cost of energy and capacity), state incentives for new solar generation (RPS carve-out for solar targets, tax credits and property tax exemptions) and, to date, state policies on QF contracting terms.

Regulatory Responses

The issues are playing out in diverse forums.

Individual states are on the front lines, since PURPA leaves much latitude to individual state utility commissions for interpreting and implementing regulations written by FERC. States are grappling independently with criteria for establishing legally enforceable obligations, definitions of avoided cost and minimum PPA terms.

North Carolina, where PURPA's resurgence has been most pronounced, offers a potential harbinger of development to come. Utilities there have faced dramatic increases in the volume of renewable power they are obligated to buy under PURPA. In the utilities' view, the pacing of these new contracts has threatened to increase their costs and disrupt their systems. In response, utilities and renewable energy developers agreed jointly to support legislation that resolves the issues for the time being. In July 2017, the Competitive Energy Solutions for North Carolina Act (or HB 589) codified an alternative to PURPA-based implementation to reflect current market realities. Among other things, HB 589 mandates competitive procurement of a fixed amount of renewable capacity over a 45-month period.

Other jurisdictions in affected / continued page 24

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Buyers in 2017 included Google, Facebook, General Motors, Kimberly Clark, Anheuser-Busch/InBev, JPMorgan, Cummins, Akamai Technologie, Target, Goldman Sachs, General Mills, Apple, T-Mobile, DeAcero, Solvay, Partners Healthcare and Paypal.

JPMorgan became one of the first banks to sign a PPA when it entered into a 20-year contract to buy electricity from a 100-megawatt wind farm owned by NRG.

Some developers are using green tariffs to arrange sales to corporations. Seventeen green tariffs have been adopted or proposed in 13 states. Most allow a company to arrange through its local utility to buy electricity from a particular renewable energy facility.

Globally, 5,400 megawatts of corporate PPAs were signed in 2017, with 75% in North America. Interest in the concept is growing in other countries.

A recent survey of 153 major companies found that 43% plan to buy renewable energy over the next 24 months. This is in contrast with the mood at a corporate buyers' conference last summer where companies seemed reluctant to lock in long-term contracts for fear that electricity prices are falling.

CFIUS is becoming a major roadblock for acquisitions by Chinese companies.

CFIUS — short for the Committee on Foreign Investment in the United States — is an interagency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign investments in US companies for national security concerns.

Reporting of transactions is voluntary. However, the committee has authority to unravel transactions after the fact that are not reported. US presidents have blocked four acquisitions since 1975 when CFIUS was created, including one last fall when President

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regions are seeking solutions too. Colorado has effectively folded its utilities' PURPA obligations into the state's electric resource planning process, which means QFs participate in a competitive bid process. Regulators in Utah, Montana and Idaho, meanwhile, have sought material reductions in the length of QF PPAs.

These state initiatives remain vulnerable to challenge for not comporting with federally established guidelines. At the federal level, FERC held a technical conference on PURPA in 2016 in which many of the law's premises were reexamined, including the mandatory purchase obligation and determining avoided costs.

As a result of the conference, FERC invited comments on minimum standards for PURPA purchase contracts and the practice by QF developers of disaggregating projects to remain under the 80-MW size limit under the protection of a one-mile rule that wind turbines and solar arrays that are more than a mile apart are not the same project. Numerous utilities and independent power developers have weighed in, as well as the National Association of Regulatory Commissioners. Comments remain under consideration by FERC.

In the meantime, the legislative wheels are also turning. The House Energy and Commerce Committee held hearings on PURPA reform in September 2017 and January 2018. The January hearing was in response to new legislation introduced in November 2017. H.R. 4476, the PURPA Modernization Act of 2017, calls for waiving a utility's mandatory purchase obligation if it conducts a competitive resource procurement process under an integrated resource plan (both of which would require approval by state regulators), or if the relevant state commission determines no need for capacity. More generally, the proposed legislation would also limit utilities' must-purchase obligations to QFs below 2.5 MW in size (down from 20), and seek to address the disaggregation issue identified in the FERC technical conference.

It remains to be seen how persistent the proliferation of renewable QFs will be. Renewable economics suffered marginal setbacks as a result of the recent change in tax law and associated contraction in tax appetite as well as the 30% tariff recently imposed on imported solar panels.

Still, for the time being, renewables have placed a new urgency on resolving old issues raised by PURPA. ◎

Renewable Energy Policy Issues in Play

Changes in government policy can have a big effect on the renewable energy market in the United States. Most acquisitions and financings make it a condition to closing that there has not been a material adverse change or proposed change in law. The parties to financings spend time negotiating whose risk it is, and what happens, if the law changes in the future before the financing has been repaid.

Five Washington insiders had a wide-ranging discussion about potential changes being debated in Washington at the annual renewable energy law conference in Austin hosted by the University of Texas in late January.

The five are Abigail Ross Hopper, president and CEO of the Solar Energy Industries Association, Tom Kiernan, CEO of the American Wind Energy Association, Daniel Simmons, acting assistant secretary of Energy for energy efficiency and renewable energy, Richard Glick, who moved in November from advising Democrats as minority general counsel to the Senate Energy Committee to commissioner on the Federal Energy Regulatory Commission, and Tom Hassenboehler, who was chief counsel for energy and the environment for the Republicans on the House Energy Committee until October, when he moved to The Coefficient Group, a Washington lobbying and strategy shop. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Solar Tariffs

MR. MARTIN: Abby Hopper, how does the 30% solar tariff announced last week play out from here? For example, is there is any expectation that some countries with whom the US has free trade agreements might get exempted?

MS. HOPPER: I think it will play out in a couple ways. There is still a fair amount of uncertainty about possible exemptions for particular products. There is also uncertainty around NAFTA and around some of our other free trading partners where I assume there will be requests to grant exemptions. The action at the country level is likely to play out in the World Trade Organization. More detail is expected from the administration in terms of process.

The tariff will have a detrimental effect on demand for solar by increasing the price, thereby making solar less competitive in many markets. That will lead to some job losses across the sector in states where the price is most on the edge.

MR. MARTIN: Do you expect the US government to carve out particular countries? The US International Trade Commission recommended Singapore, Israel, various countries in Latin America and other places with which the US has free-trade agreements for relief.

MS. HOPPER: No. The president put out some information last week that said that developing countries are exempted to the extent their total solar cell or panel supplies to the US remain below certain thresholds, but he specifically took out a few important ones like Malaysia, Thailand and South Korea. None of those is exempted.

MR. MARTIN: According to news reports, Sunpower plans to ask for relief for one of its products — a high-end solar panel — and solar-powered pack backs are expected to be carved out. Do you have any sense for what standard will be used to determine what products will be exempted?

MS. HOPPER: I don't. I think we expect to see a process and perhaps standards announced by around February 22.

MR. MARTIN: Are you hearing already from your members about any particular market disruptions?

MS. HOPPER: The nine months of uncertainty definitely affected the market. Some projects were delayed or cancelled due to inability to determine what modules cost. This then made it hard to commit to a price to supply power and made it harder to secure financing for projects.

Going forward, I don't know. It has been a week since the tariff was announced. I think companies are still trying to wrap their arms around what exactly this means. Overall, there has been a chill in the market.

MR. MARTIN: Three more questions, and then we will move on to something else. What are you hearing about where panel prices are likely to settle?

MS. HOPPER: That's a million dollar question. Some people say the risk was already priced into the market and so we may not see an incremental 30% bump due to the tariff.

MR. MARTIN: The last time the US imposed these types of tariffs was on steel imports in 2002 under President George W. Bush. The tariffs remained in place for two years before the US removed them. The WTO allowed other countries to impose retaliatory tariffs on some US products. What are your advisers telling you about the likelihood that South Korea, Mexico, Taiwan, China or other countries will be able to prevail in the WTO?

MS. HOPPER: I am not a trade lawyer, although I feel like I played one for the last year. What I am told is that the United States has never won a safeguard case

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Trump blocked Canyon Bridge, a China-backed private equity fund, from acquiring Lattice Semiconductor Corp. in Portland, Oregon for $1.3 billion based on a CFIUS recommendation.

Most transactions with which the committee has trouble are withdrawn before reaching that stage.

In January, an Alibaba affiliate, Ant Financial Services Group, had to abandon a proposed $1.2 billion acquisition of MoneyGram International Inc. in Dallas after CFIUS objected to the sale. The deal would have given Ant access to 2.4 million bank and mobile phone accounts. The fear was that access to so much consumer data could lead to identity theft or be used to damage credit ratings or gain access to bank accounts. Chinese state entities own 15% of Ant.

HNA Group Co. Ltd. abandoned a proposed investment in Global Eagle, US flight entertainment service provider, following CFIUS disapproval late last year.

Anthony Scaramucci, who spent 10 days as Trump's White House communications director, disclosed on *Real Time with Bill Maher* on HBO in early February that the proposed sale of his fund of funds, Skybridge Capital, to HNA was rejected by CFIUS.

Cowen, a US small investment bank, abandoned a $275 million investment by CEFC China Energy in December due to delays at CFIUS.

CFIUS rejected a bid by Chinese internet company Tencent and Chinese mapping company NavInfo in September to buy 10% of Here, an Amsterdam-based mapping company with assets in Chicago.

A $2.7 billion deal for China Oceanwide Holdings Group Co. to buy Genworth Financial Inc., an insurer in Richmond, remains on hold. The deal was announced in October 2016. The company refiled with CFIUS for the third time in early February.

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Policy Issues

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at the WTO. It takes 18 months to two years to move through that regulatory process.

The president's inclusion of Canada and Mexico in this tariff triggers some different legal remedies under NAFTA that I think could put pressure more quickly on the US than what is likely to come from the WTO process.

MR. MARTIN: Most of the ire in the president's tariff proclamation was directed at China. We already collect anti-dumping and countervailing duties on Chinese panels. China has shifted a lot of its production to places like Malaysia. Are there any discussions with China aimed at resolving our differences that might lead to tariff relief?

MS. HOPPER: That's a good question. We call it the global settlement or the grand bargain. I think there are such discussions. The president referred in his proclamation to continuing to work on a settlement. Talks have been underway for years, so it will take some leadership by the administration, but there is an interest among all concerned in having those discussions.

Perry Plan

MR. MARTIN: Rich Glick, were you surprised that the Federal Energy Regulatory Commission voted unanimously to reject the proposal by US Energy Secretary Rick Perry that nuclear and coal plants should be dispatched ahead of other types of generation and assured a profit, and where do you see things going from here?

MR. GLICK: I was not particularly surprised. The record did not have any evidence to suggest that increasing payments or subsidies to nuclear and coal plants will make the electricity grid more resilient. If anything, the evidence suggested the opposite.

The Department of Energy's own study last summer suggested that nuclear and coal plants have resilience issues of their own and favoring those types of plants over other forms of generation is unlikely to improve grid resiliency.

There was a big cold snap in the eastern half of the United States a couple weeks ago. Many of the power plants that had to be shut down due to the weather were the nuclear and coal plants.

The commission rejected the Perry proposal and opened a new proceeding in which we are asking grid operators who are subject to commission jurisdiction to submit information within 60 days about any resilience problems they see and, if there are any, what they believe the commission should do about them.

I suspect we will receive a wide range of opinions. After the 60 days, there will be another 30 days for public comment on what the grid operators submit.

I plan to look at the record in the proceeding, but if there is no indication of a near-term problem with resilience, then I think we need to end the focus on this subject and move on. FERC has a lot of other issues begging for action, in large part because the commission lacked a quorum for most of last year. We need to move on to these other issues if there is really no evidence that we need to do something immediately about resilience.

MR. KIERNAN: Let's give credit to FERC. This was a unanimous, bi-partisan decision in a period when much of government has not been functioning in such a manner.

MR. MARTIN: Several states — Illinois, New York, Connecticut, New Jersey — are moving to offer things like zero emissions credits and other subsidies to keep nuclear plants operating. Is this something on which FERC should weigh in?

MR. GLICK: This is an issue to which everyone in the renewable energy community needs to pay close attention. It could have a big impact on state renewable portfolio standards and other state programs that try to incentivize renewable energy generation.

> Legal wrangling over state subsidies for nuclear power plants and a federal "modified clean offer rule" have the potential to affect state renewable portfolio standards.

Beyond that, I need to be careful because there are some pending cases at the commission, and I am not allowed to talk about any pending cases and must not to prejudge matters.

In general, the US Supreme Court, in a case several years ago, said that states are preempted from enacting programs that have the effect of regulating pricing in the wholesale power markets. But the court was silent on whether a state can have a renewable portfolio standard or can favor nuclear or some other form of generation to the extent it does so in a manner that does not replace wholesale electric rates.

We are in a situation where the legal precedent is a little unclear. We have several cases pending before the commission dealing with a "modified offer price rule," or MOPR, that is of particular concern in the organized markets in the eastern United States. The issue is whether state energy policy programs are causing some generating resources to bid into capacity auctions in such markets at less than their marginal costs and, if so, whether that is something that FERC needs to address.

The issue is a slippery slope. Where do you draw the line on state programs? Do we take the position that states cannot address certain externalities that the energy markets fail to take into account, like greenhouse gas emissions for instance? Do we take the position that states cannot have renewable portfolio standards or programs favoring other types of generation?

Congress bifurcated resource decisions in 1935 by giving the power over retail electric service to the states and leaving the Federal Power Commission — now FERC — with wholesale electric rate and transmission oversight. I am a little troubled that the MOPR proceeding could lead to a situation where you end up limiting the ability of states to address what they see as legitimate concerns.

MR. MARTIN: So you think FERC should stay out of it?

MR. GLICK: I have not made up my mind, but I am troubled by the concept that FERC can override state resource policy decisions.

MR. MARTIN: Dan Simmons, before you moved to your current position at the Department of Energy, you were a critic of the federal government favoring any one type of energy. You thought resource decisions should be left to the market. How do you reconcile this position with the effort by the Trump administration to favor nuclear and coal?

MR. SIMMONS: My position has always been that the federal government should not be in the business of picking winners and losers. That is where I am personally, but that is obviously not necessarily the position of the administration.

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IN OTHER NEWS

CFIUS has a line of deals awaiting review. Refilings are common.

The committee approved a small Chinese acquisition in December. Chinese semiconductor manufacturer NAURA Technology Group Ltd. got approval to acquire Akrion Systems, a semiconductor cleaning company in Allentown, Pennsylvania, for $15 million. The deal was first announced in August 2017.

New Chinese direct investment in the United States was around $29 billion in 2017.

AIRCRAFT NON-PAYMENT INSURANCE is being used in some aircraft financings.

An insurance company guarantees payment of debt service on a loan. The basic concept is similar to a loan guarantee provided by a government export credit agency, according to Bob Haken in the Norton Rose Fulbright London office. The lender relies on the credit of the insurance company when deciding whether to extend the loan. The insurers have the equivalent of at least a single-A credit rating from Standard & Poor's.

The lender enters into a loan agreement and advances funds that are used to buy the aircraft. Insurance cover protects the lender against a borrower default.

The premium for the insurance is paid in full on the drawdown date for the loan and can be financed as part of the loan amount, like an ECA guarantee premium, says Haken.

The insurer agrees to make any missed payment on the loan. There is an assumption once the borrower misses one payment that it will continue to skip others, so the insurer continues making payments until the earlier of a set period — for example, 18 months — or the date the aircraft is sold. If the aircraft sale fetches too little money to repay the loan balance and accrued but unpaid interest, then the insurer makes up the shortfall.

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Other Big Issues

MR. MARTIN: Let me ask the entire panel, starting with Tom Hassenboehler, what are the other big policy issues on your agenda this year aside from the Perry proposal, the MOPR proceeding that Rich Glick just mentioned and solar tariffs?

MR. HASSENBOEHLER: Congress has been largely on the sidelines in these debates. There is talk about reviving an energy bill that stalled last year. There was also an effort last year to put together a targeted package of public lands bills coupled with some other modest reforms in the Department of Energy.

There is not a huge appetite in Congress currently for large, bold initiatives, but I think there is a growing desire among Republicans to be relevant again in the energy space and to engage on some of these issues, including on the Perry NOPR. The House Energy and Commerce Committee launched a "Powering America" series of hearings that looked at emerging issues, from the federal-state jurisdiction questions that Rich Glick mentioned all the way to the historical origins of the Federal Power Act and how new technology and digitization of the economy and renewable integration may require changes in federal regulation. In the longer term, Congress will need to tackle these issues.

We have a lot of litigation coming up this year, and a lot of FERC decisions have the potential to stir Congress. In addition to that, it is possible that a small energy bill could hitch a ride on the infrastructure package that the president wants to put through Congress.

MR. GLICK: There are three other policy issues in play that are relevant for this audience.

One is a pending rulemaking that was proposed in 2016 that would enable energy storage and distributed energy resources to bid into the wholesale power market. Energy storage lacks the ability currently to fully monetize the benefits it provides. The ability to participate in the wholesale market should make storage more economic to install.

Next, we are looking at generator interconnection reform. The commission proposed a rule a while back. It is still pending. There is a lot of interest, especially from solar and wind companies, to streamline the interconnection process.

The third issue is PURPA. Congress is taking a look at PURPA reform and so is FERC. There was a technical conference a while back. The state regulators in particular are really pushing FERC to change how we implement PURPA.

MR. SIMMONS: The administration is focused on affordable and reliable energy to promote economic growth and energy security. Those four items — affordable energy, reliability, economic growth and energy security — are at the core of where the administration wants to go on energy.

Affordability is critical. Reliability is critical. You see that in what Secretary Perry asked the Federal Energy Regulatory Commission to do. Economic growth is critical as is energy security. You will hear a lot about both tomorrow night from the president in his State of the Union address to Congress.

Along with those, there will be a big infrastructure push this year. Finally, one of the important takeaways from the grid study that we did at the Department of Energy at Secretary Perry's request was how to ensure that there is adequate compensation for grid reliability services. Those are what I see as our priorities.

MS. HOPPER: After the solar tariff and the Perry NOPR, our biggest federal priorities are moving away from playing defense. We are thinking about the infrastructure bill and the ways that solar, and energy in general, are addressed as part of any new national infrastructure plan.

Another issue is monitoring how the new tax law is affecting the solar sector and engaging with the government on some of the guidance needed to implement it.

PURPA obviously is an issue we care deeply about. State policies can also have a significant effect on the solar market and on energy security and reliance, and we continue to monitor potential changes at the state level.

Tom Kiernan and I have a personal and an organizational commitment to working on many of these things together. So debates around transmission planning, and how we participate in wholesale markets, are areas in which we are going to be working together.

MR. KIERNAN: Two priorities, somewhat consistent with what Abby and other panelists have said.

One is getting more transmission so that the grid as a whole is more reliable and so that we can move electricity from the windy places where wind farms are built to where people live.

The other is market design, meaning making sure that we have competitive markets with effective pricing of electricity and of essential reliability services. I agree with Daniel Simmons that all electricity generators — wind, solar, others — should be able to compete effectively to provide reliability and resilience services and be compensated for them.

Transmission and market design benefit all sources of electricity. The more transmission and more competitive a market design we have, the better off consumers are because those policies would help reduce the cost of power.

Energy Bill?

MR. MARTIN: Tom Hassenboehler, you mentioned an energy bill as a possibility this year. Rich Glick, you just came off Capitol Hill as well. What is the likelihood of an energy bill, even a small one, being attached to a larger infrastructure bill, and is there anything in the energy bill that will affect people in this room?

MR. HASSENBOEHLER: There is a commitment by the four key members at the committee level in the Senate and House to try to do something, but the enemy this year is time. It is very hard to get anything on the legislative calendar during an election year, since the calendar tends to be taken up with must-pass items like funding for the government and the need to raise the public borrowing limit and with messaging bills that the party in control wants to put through in advance of the elections.

There is a bipartisan energy bill that actually has consensus and buy in by both parties. Sometimes those kinds of measures can creep in during an election year. A lot of work was done on it in conference between the two houses last year, as Rich knows. He and I worked on it together on the Hill. The real issue will be getting time on the calendar.

MR. MARTIN: Rich Glick, what odds do you give an energy bill this year?

MR. GLICK: The bill passed the Senate last year by an 85-to-12 vote, which is very unusual in the current Congress, but it is tough to do anything in the current environment.

There is nothing earth shattering for this audience in the bill. There are a few provisions, such as R&D for energy storage, the smart grid and geothermal development on public land that might be helpful.

MR. MARTIN: Tom Kiernan, is there anything AWEA is watching in the energy bill?

MR. KIERNAN: We want to see improvements in transmission, so we are having some discussions about it, but that's about it.

Effects of New Tax Law

MR. MARTIN: Abby Hopper, are you hearing any complaints from your members about the new tax law and, if so, what?

MS. HOPPER: There has been some discussion about the base erosion and anti-abuse tax — BEAT — and its potential effect on the tax equity market. BEAT has a / continued page 30

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US RESIDENTIAL ROOFTOP SOLAR installations fell for the first three straight quarters in 2017 as some of the major players adjusted their business models to make upfront cash more of a priority than rapid growth.

The national brands now account for 30% of the residential solar rooftop market.

Use of the third-party ownership model, where the rooftop company installs solar for free on roofs of customers who enter into long-term power purchase agreements to buy electricity or leases to lease the systems accounted for 37% of the residential rooftop market in 2017, down from 53% the year before. More customers are buying their rooftop systems rather than merely buying electricity or leasing a system owned by a solar company.

Utilities are under pressure in 16 states to reduce retail electricity rates after Congress cut the corporate tax rate from 35% to 21% effective on January 1. This, plus the new tariffs on imported solar panels, could make the rooftop model relatively more attractive, since pricing starts at a discount to local retail electricity rates. Customers were deciding earlier to purchase systems after watching equipment costs fall more rapidly than retail rates.

Andrew Birch, former CEO of Sungevity, a prominent early residential rooftop company that went bankrupt, wrote in GTM in January that the average installed cost for a rooftop system in the US was $3.25 a watt in December compared to $1.34 a watt in the main Australian markets. Birch attributes the higher cost in the United States to local red tape. He said it can take two to six months to get permission to install and turn on a rooftop system in the US, while in Australia, interconnection is a simple matter of completing an on-line form.

Birch said city-level bureaucracy adds 47¢ a watt to solar installations in the US. Import tariffs add more.

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differential impact on wind versus solar. There are some indications that the intense anxiety we felt in early December may not bear out in terms of getting deals done after the 80% renewables fix that Congress added to the BEAT in conference.

The decrease in the corporate tax rate reduces the value of the depreciation on projects and, therefore, the amount that can be raised in the tax equity market.

The lack of guidance is problematic, and that is where I am hearing more complaints. There are some areas where we need more clarity on how the new rules of the road work.

MR. MARTIN: Tom Kiernan, what are you hearing from your members?

MR. KIERNAN: On the BEAT, the general sense is it will hurt by reducing the amount of tax equity that can be raised for projects. How much and whether that will tank some projects is to be determined. We have heard of some projects slowing down as some tax equity investors take stock of how they will be affected by BEAT, but our sense at the end of the day is projects will move forward, albeit potentially at a higher cost of capital. There is still some analysis to be done.

MR. MARTIN: Is there an effort underway on Capitol Hill to try to improve on the 80% fix for the BEAT?

MR. KIERNAN: There are a number of ideas floating around for how to get rid of any remaining potential for the BEAT to claw back tax credits or to further reduce the potential cost to tax equity investors who are subject to the BEAT.

There was a bipartisan deal in 2015 in which the wind industry actually proposed to phase out production tax credits for wind over a ramp-down period of four years. The goal has been to preserve that deal and not weaken it through the BEAT. So there are some discussions on fixing the 20% claw back, but nothing definitive.

MR. MARTIN: Rich Glick, 12 state attorneys general wrote FERC in early January asking it to force utilities to pass through the corporate rate reductions to their customers. I assume that just means pipelines and transmission companies, since those are the only utilities over which FERC has jurisdiction. Does FERC have a potentially broader role?

MR. GLICK: We are taking a look at it now and are waiting for a memo from the commission staff. Clearly there are opportunities to reduce rates where utilities are recovering taxes at a 35% tax rate, so that needs to be adjusted, and I think we need to do it quickly. I understand the issue may be a little more complicated for pipeline companies because of the way their rates are set. However, I think we will be acting on this fairly soon.

> A grand compromise could emerge to fix complaints by utilities about PURPA and by independent generators about access and utility actions.

MR. MARTIN: On what timetable do you see FERC acting?

MR. GLICK: The chairman makes that decision, but certainly this year and hopefully in the first half of this year.

MR. MARTIN: Dan Simmons, you told *PV Magazine* in September that you are concerned about the fact that wholesale electricity rates have fallen dramatically while retail rates remain sticky downward. To what do you attribute this?

MR. SIMMONS: I don't know, but we hear about how power purchase agreements are being signed by generators at lower and lower rates to supply power, and then you look at retail rates and, instead of decreasing, they are increasing slightly. I am very concerned. I do not see a federal role for regulation in this area, but there is an important federal role in researching what is going on.

PURPA

MR. MARTIN: Let's move to PURPA, a 1978 law that requires electric utilities to buy electricity from independent generators in some parts of the country at the avoided cost the electricity would pay to generate the electricity itself.

Both Rich Glick and Tom Hassenboehler mentioned it. There is an effort before both Congress and FERC to water down the remaining purchase requirement. Tom Hassenboehler, starting with you, what are the principal issues in the PURPA debate?

MR. HASSENBOEHLER: The House Energy and Commerce Committee held a hearing on a draft bill about a month ago. There are basically three issues.

The first two are things that FERC can do administratively. The utilities want to amend the one-mile rule.

MR. MARTIN: So multiple wind turbines will be considered a single project even though they are more than a mile apart if they function like a single project. This is important because utilities are not required to buy electricity from projects once they pass a certain size.

MR. HASSENBOEHLER: There would be a rebuttable presumption that the turbines are a single project. The existing FERC guidance requires that turbines that are more than a mile apart be treated as separate projects.

The second issue is some utilities want to reduce the size of projects from which they are required to buy electricity in organized markets from 20 megawatts to 2.5 megawatts. This is something that I believe FERC can do administratively.

The third thing is to let the states make the decision when the mandatory purchase requirement should apply. Basically it would remove from FERC the ability to require utilities to purchase, which could lead to state-by-state variances in how PURPA is implemented across the country.

MR. MARTIN: It would make the PURPA purchase requirement optional. States would decide.

MR. HASSENBOEHLER: Yes. Those are the three main proposals in the bill. It is in the legislative hearing phase. Many of the utilities appear to be aligned on what they want. Obviously not all the independent generators see eye-to-eye on these changes. The prognosis for it moving in the House is a little above 50%. There is growing interest in addressing these issues.

However, my guess is it is going to take a little while to get all the way through Congress. In the meantime, FERC has the ability to do some of these things on its own.

MR. MARTIN: Rich Glick, why is there both a FERC technical proceeding and this legislative process? Is this the utilities trying to open both doors? Also, I thought I heard at one point last year that it was possible PURPA might actually be expanded.

MR. GLICK: The utilities have been on Capitol Hill about these issues for a number of years and, for a variety of reasons, have not been able to get the changes they want, in large part because it is very difficult to get anything like / continued page 32

IN OTHER NEWS

The National Renewable Energy Laboratory reported in January that a three- to 10-kilowatt residential solar system cost $2.80 a watt to install in the US in the first quarter of 2017.

NEW WIND FARM construction dipped in 2017, but should pick up again in 2018.

There is fear that a lot of projects are being pushed into 2019 and 2020. There is evidence that construction companies that erect turbines are already becoming booked for 2020.

Grid congestion has emerged as the other top concern. Some wind CEOs say that they can build wind farms, but there is no room on the grid to move electricity in places like MISO, the section of the US grid from Indiana and Michigan west to eastern Montana.

The US added 7,017 megawatts of new wind capacity in 2017, compared to 8,200 megawatts the year before, according to data released by the American Wind Energy Association at the end of January. New construction is expected to return to about 8,000 megawatts in 2018.

Total US wind capacity was 89,077 megawatts at the end of 2017.

Wind developers reported 13,332 megawatts of projects were under construction, and another 15,336 megawatts of projects were in advanced development, at the end of 2017.

According to FERC data, US wind developers have proposed 465 new wind farms with a combined capacity of 72,560 megawatts through the end of 2020. A little more than half the projects are expected to be built.

MAKE, a consultancy, estimates that enough equipment was stockpiled by wind developers in 2016 to allow 45,000 megawatts of wind farms to qualify for federal tax credits at the full rate. A flurry of additional equipment purchases in 2017 qualified up to another 10,000 megawatts of projects for tax credits at

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this through the Senate. You have to get 60 votes. The ranking Democrat on the Senate Energy Committee, Maria Cantwell, has basically said, "Over my dead body." She is a pretty formidable legislator.

I think the utilities are a little frustrated, so they have come to FERC and suggested FERC should address some of these issues.

Congress narrowed the purchase requirement in 2005 to generators in parts of the country where they do not have the option to bid into a competitive power pool. It said that there is a rebuttable presumption that utilities do not have to buy from a facility that is more than 20 megawatts in size and interconnected to a grid operated by a regional transmission organization or independent system operator that has certain elements of a competitive market. For facilities up to 20 megawatts, there is a different story. There is a rebuttable presumption that such a facility lacks competitive access and, therefore, the must-purchase requirement still stands.

Much of the western US does not have RTOs and ISOs. There are a lot of solar facilities in North Carolina that also rely on PURPA. People have made the determination that in those regions, in particular, small renewable energy generators need access to PURPA to be able to get utilities to sign power purchase agreements.

The debate over the one-mile rule has become fairly heated. The issue is whether wind turbines or solar arrays that are more than one mile apart should be considered different facilities for determining the size of the power plant. No utilities — in or outside competitive markets — are required to buy electricity from renewable energy facilities that are more than 80 megawatts in size.

There is also a debate around whether the separate 20-megawatt cap for the purchase requirement in competitive markets should be reduced to 2.5 megawatts.

FERC has authority to address these issues and, when I was on Capitol Hill, I would always say, "We should leave it to FERC to address." Now that I have a different role I think a lot of these issues are better addressed by Congress. [Laughter]

That said, I would not be surprised if we see a rulemaking at some point — not in the near future, but at some point down the road — addressing some of these issues.

MR. MARTIN: Is it possible that PURPA might actually be expanded instead of cut back?

MR. GLICK: Possibly, in some areas. I still have to review the record from the technical conference more closely, but I think you could see a grand compromise, whether legislatively or administratively, where some of the complaints by utilities get fixed at the same time some of the other complaints that generators make about access and about utility actions that the generators say suppress competition also get addressed.

MR. MARTIN: Abby Hopper, how big an issue is PURPA for solar?

MS. HOPPER: It is a fairly large issue for the solar industry, and we are engaging with Congress and FERC on these issues. North Carolina is the second largest solar market in the US, and a large part of that is because of PURPA. We think PURPA is an important tool. We are always happy to talk about ways to streamline it or make it more efficient, but we are not in favor of subverting the underlying purchase requirement.

MR. MARTIN: Tom Kiernan, how big an issue is it for wind?

MR. KIERNAN: Not particularly a big issue. Most wind farms being built today are too large to benefit from PURPA.

Transmission

MR. MARTIN: There was talk at the start of the Obama administration about making it easier to build new transmission lines. Little headway was made. Is the effort hopeless?

MR. SIMMONS: Let's see what comes out with the infrastructure push. We heard from a lot of people early in the administration about the need for help with transmission siting. One thing the administration can do is streamline the federal environmental review under the National Environmental Policy Act. Long drawn-out agency processes are a concern for transmission. That's one area where we hope to make a difference.

MR. MARTIN: Rich Glick, you were quoted last week in the press as saying that the government ought to give greater weight to local views when it comes to siting new gas pipelines. Isn't the inevitable local opposition the main impediment to building new transmission lines?

MR. GLICK: It would take a while to explain, and I can't talk fully about this because it is a pending matter before the commission, even though I dissented in the case. There may be a rehearing. But I will say this: FERC has authority to site natural gas pipelines. It does not have that authority for transmission. The Natural Gas Act requires the commission to find the pipeline is essentially in the public interest.

In order to determine whether it is in the public interest, you need information. In some cases, states do not give developers of proposed gas pipelines access to the information we need to make an informed decision, so the developers come to FERC and say, "Why don't you just grant us the certificate? We'll come up with that information later because we can use eminent domain once we get the certificate. Then we'll provide the information for you, and you can make up your mind whether it is in the public interest." To my mind, that is backwards.

The new FERC chairman announced in his first public meeting that the commission will review its natural gas policies because there are questions about whether we are following the precedent the commission set in the 1990s on natural gas pipeline siting. I hope access to information will be addressed in that proceeding.

Solar Goal

MR. MARTIN: Dan Simmons, the Department of Energy set a goal in 2011 to cut the cost of solar to 6¢ a kilowatt hour by 2020 to support broader deployment. That goal was reached last September. Will a new goal be set for solar?

MR. SIMMONS: Yes. We have a new goal. That is for utility-scale solar with an average amount of sun, so it would be for an area like Kansas City as opposed to, say, Texas or Arizona. Our goal is to move to 3¢ a kilowatt hour by 2030. Goals are important and, in focusing our efforts to drive down cost, affordability is one of the keys for the Trump administration and that includes continuing to reduce the cost of wind, solar and other types of generation.

MR. MARTIN: Abby Hopper, does 3¢ a kilowatt hour by 2030 sound like an achievable goal or is it perhaps not ambitious enough?

MR. SIMMONS: Maybe not ambitious enough. What do you say, Abby?

MS. HOPPER: Maybe not ambitious enough. I have the utmost confidence that we can meet it. The biggest challenge in reducing costs is not the technology or equipment, but soft costs that make up a big chunk of the cost of a project. To the extent that DOE is doing work on how to reduce soft costs as well as the technology costs, that is incredibly important.

I come from the great state of Maryland. Every county has a different standard for how it inspects solar projects, and that is intensely inefficient and cost-prohibitive. So keep working. That's great.

MR. MARTIN: Rich Glick, shortly after / *continued page 34*

IN OTHER NEWS

80% of the full rate. MAKE says another 16,000 megawatts of projects may have been under construction in 2016 or 2017, thus qualifying for tax credits, based on physical work on the site or at a factory on turbines, transformers or other equipment.

Oklahoma is now second in installed capacity, after Texas. (See related news item on "An Oklahoma Bill" in this issue.) Installed capacity in Texas is 22,637 megawatts. Oklahoma has 7,495 megawatts. The two states alone account for a little over a third of all US wind capacity.

Wind developers signed 3,317 megawatts of power purchase agreements with utilities in 2017. Another 2,178 megawatts of PPAs were signed with corporate offtakers. (See related news item on "Corporate PPAs" in this issue.)

There were 2,136 megawatts of repowerings of existing wind farms in 2017, a large part of it by a single developer. Repowerings are expected to pick up from 2018 through 2020.

Four turbine vendors had 99% of the US turbine market. Vestas led with a 35% market share. GE had 29%, Siemens Gamesa 23% and Nordex 11%.

US OFFSHORE WIND is gearing up quickly.

Eight offshore wind projects are in the works off Massachusetts, New York, New Jersey, Maryland and Virginia.

The New York State Research and Development Authority, or NYSERDA, released an "Offshore Wind Master Plan" at the end of January to develop 2,400 megawatts of offshore wind, with 800 megawatts in commercial operation by 2025 and the rest to be completed by 2030.

New Jersey Governor Phil Murphy (D) issued an executive order two days later asking state regulators to solicit 1,100 megawatts of offshore wind initially, and then reach 3,500 megawatts by 2030.

A 2016 Massachusetts law requires the state to solicit 1,600 megawatts by 2027.

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the Trump victory I asked you how you thought the Trump energy and environmental policies would affect renewable energy. The president threatened during the campaign to withdraw from the Paris climate accord, cancel the Obama Clean Power Plan, promote coal and build the Keystone pipeline. You said you did not expect much of an effect in the short term. Is that still your view?

MR. GLICK: Yes. Corporate demand for renewables is growing. Utilities are buying more renewables because they know they will lose their corporate customers if they don't do that. Also, key states are continuing to encourage a shift from fossil fuels to renewable energy.

In the longer term, when the tax credits for renewables expire, things become a little more murky.

MR. MARTIN: People thought in 2015 when the deal was cut to phase out tax credits that the phase out would take the industry through 2020, when the Paris climate accord and Clean Power Plan would start to kick in as a driver. Those are both gone now. How important were they?

MR. KIERNAN: It was unfortunate to find them pulled away. However, the main driver for growth in renewables is the continued reduction in the cost. The cost of a wind farm has fallen by 66% in the last seven years, and costs continue to fall. Both corporate buyers and utilities are realizing that renewable electricity is becoming really inexpensive, so they say, "Let's buy it. Let's buy a lot of it."

State RPS targets and integrated resource plans will continue to help after 2020.

MS. HOPPER: I would add on the solar side that as we look at procurements for 2017, about two-thirds of them were based on cost. They were not policy-driven decisions. They were price-driven decisions. We hope to make it on cost.

MR. HASSENBOEHLER: We are in a good place where costs are coming down and equipment is becoming more efficient as a result of policies of the past. The mandates, subsidies and tax credits did the job they were supposed to do.

I think we are entering a phase where consumers are really driving things. The combination of digitization of the industry and emergence of new technologies has the potential to take it from here. The question is whether the market rules will allow the large corporate purchasers to do the things that they claim they want to do.

Assuming the market rules are accommodating, the branding and the environmental awareness from the bottom up versus the top down should continue to drive renewables, regardless of whether the Clean Power Plan ever comes back or whether a price is put on carbon.

State Skirmishes

MR. MARTIN: We are down to the last three questions. Renewable portfolio standards have been a driver for renewable deployment at the state level. The Koch brothers have been funding an effort to roll back the standards in some states. How do you see this battle playing out? Who is winning?

MR. KIERNAN: That battle will continue, but in the last several state legislative sessions, more states have been increasing their RPS targets or moving forward on new RPS targets because that is what consumers are looking for. They want clean, renewable electricity. Renewables are rapidly becoming the lowest-cost electricity.

MR. MARTIN: There was a prediction that when Trump took office attention would shift to the states as the federal government lost interest in promoting renewable energy. Abby Hopper, what is the next biggest state issue, after RPS targets, that you are following? You are a former state energy official.

MS. HOPPER: On the solar side, the net metering conversation continues to be alive and well. It plays out in legislatures, and it plays out in a lot of regulatory proceedings. These are intensely time-consuming and detailed proceedings, but we have a rate design expert on staff now because we are participating in so many such proceedings across the country.

I agree with both Toms that consumers are driving demand for renewable energy at this point. That consumer preference is being felt from one state to the next. Sometimes it is RPS. Sometimes it is tax rebates. Sometimes it is some other program to help fuel the move to renewables, and it is happening across the country.

MR. MARTIN: Last question for Dan Simmons. You oversee the National Renewable Energy Laboratories, which are doing very interesting work. Is there one thing on which they are working that should excite this audience?

MR. SIMMONS: If you ever get the chance to visit any of the national labs, I suggest you take advantage of that opportunity because they are great. There is no one thing. There are many things, such as in the area of solar, almost sci-fi technologies such as spray-on coatings that allow all manner of equipment to generate its own electricity to much more mundane issues such as increasing the value of power electronics so that wind and solar are able to produce better grid reliability services in terms of frequency and voltage support.

Other exciting areas are control strategies that can turn buildings into sources of virtual storage for the grid and better communication that makes the grid more complex, but also creates new sources of value, which is one of the reasons why the issues of price formation and assigning the right value to grid reliability services are so important. ◎

ERCOT: Shrinking Reserve Margin

Texas is the only organized electricity market in the United States where there is growing demand for electricity. ERCOT's latest capacity, demand and reserve report projects a 9.3% reserve margin by this summer, which is below the 13.75% target. Some developers see an opportunity for new flexible generation, like gas peakers, that can balance out the large amount of wind farms on the ERCOT grid. Large base-load power plants are being retired because wholesale power prices are so low in ERCOT, due to low natural gas prices, that it is hard to recover fixed costs. However, developers of peaker plants expect electricity shortages this summer that will allow such power plants to make money off price spikes. There could also be development of new "switchable" power plants along the southern border to sell capacity into Mexico while continuing to earn energy payments in ERCOT.

Three close observers of the Texas market talked at the Infocast "projects & money" conference in New Orleans in January about the Texas market. The three are Karl Dahlstrom, a partner in Halyard Energy Ventures, which has 2,000 megawatts of natural gas peaking plants and 100 megawatts of storage facilities under development in Texas, Bob Helton, senior director of regulatory affairs at Dynegy, a large Texas-based independent power company, and Kevin Smith, president of Tenaska Power Services Company, which transacts physical and financial wholesale power and provides congestion management, hedging scheduling, settlement, market interface and other services for 44,000 megawatts of third-party generation. The moderator is Deanne Barrow with Norton Rose Fulbright in Washington.

MS. BARROW: ERCOT is undergoing a number of fundamental changes. Karl Dahlstrom, what are they?

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AN OKLAHOMA BILL that would cap tax credits for generating wind electricity and, at the same time, impose a tax on such electricity fell short of the number of votes needed to pass the state house of representatives in mid-February.

However, another vote is expected before the legislature adjourns in May.

Tax increases require a 3/4ths vote to pass.

The vote for the bill was 63-35 in the 101-member house of representatives after oil and gas interests turned against the bill because it would double an initial gross production tax on oil and gas produced from wells during the first 36 months of production.

The legislature must find a way to plug a budget gap before it adjourns.

The state allows a tax credit of 0.5¢ a KWh of wind electricity for 10 years after a project is first put in service. The state moved up the in-service deadline to July 1, 2017 from the end of 2020 last year to save money.

The bill would cap the credits that can be claimed each year at $18 million.

It would also impose a tax on wind electricity of 1¢ a KWh, or twice the tax credit amount.

If the tax is imposed, Oklahoma would become the third state to tax wind electricity. Wyoming taxes wind electricity at 0.1¢ a KWh. South Dakota imposes taxes of 0.065¢ a KWh on wind farms that commenced operating between July 1, 2007 and March 31, 2015 and 0.045¢ a KWh for wind farms that went into operation more recently.

MAINE imposed a moratorium on new wind farm construction.

Maine Governor Paul LePage (R) ordered a halt by executive order on January 24 and appointed a commission to study the effect of wind farms on tourism. The commission has no deadline to report.

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MR. DAHLSTROM: The largest fundamental in ERCOT is consistent load growth. ERCOT has seen about 1.5% load growth per year for the past few years, and it looks like this this will continue for the foreseeable future. In a market of about 70,000 megawatts, that means about 1,000 megawatts a year of additional capacity is needed.

MS. BARROW: Bob Helton, anything to add?

MR. HELTON: The Texas Public Utility Commission has a docket open to look at some very fundamental and large changes to the market. We are an energy-only market, which means that all your revenues have to come from the energy produced or the ancillary services market.

We are revisiting whether to move to a capacity market. We are looking at possibly changing our operating reserve demand curve. We are looking at changes to reliability unit commitment. I think there is a high chance of the reliability unit commitment changes before summer. The odds of the operating reserve demand curve changes are not as high.

Another issue is now to deal with marginal losses, but that is very contentious and down the road, if it happens at all. When it comes to whether that helps or hurts, it depends on what marginal losses you have. I am not sure that it will curtail any renewables that are being built, even though that is the goal of some people pushing it. Another potential change is co-optimization in real time. We will see it eventually, but it is five years down the road.

General Trends

MS. BARROW: So load growth and potential market reform. Kevin Smith?

MR. SMITH: Coal retirements are another big fundamental change in ERCOT. There have been announcements in the last few months that about 5,000 megawatts of coal is being retired, almost all of it early this year with the rest at the end of the summer. That will have a material effect on capacity reserves. The expectation is that we will see more scarcity pricing this summer than we have in the past.

MR. HELTON: The overall picture is a mixture of retirements, load growth and the renewables that have been built. There are more than 20,000 megawatts of wind farms alone that are non-dispatchable resources. You couple that with the low cost of natural gas and strong supply and it is making it harder for base-load plants to cover their fixed costs. I think the story in ERCOT is a mixture of regulatory, load growth, increased renewables, retirements and low price of natural gas.

MR. SMITH: You said a mouthful.

MS. BARROW: Vistra Energy is retiring, as Kevin said, almost 5,000 megawatts of coal capacity. What does the panel feel is best placed to replace it?

MR. DAHLSTROM: This may sound a little self-serving, since I am a greenfield developer of natural gas peakers in ERCOT, but if you look at the fundamentals we just talked about, we think that the market will require flexible generation with low installed costs and low operating costs to help balance out the renewables. Thus, our view is that the generation to replace coal should be low-cost gas peakers as well as battery storage.

MR. HELTON: I can't argue with that. Flexibility, flexibility, flexibility is going to be the rule of the game moving forward, especially with the volume of renewables being built. The question is when is the right time to bring gas peakers on line, and that is where I think we get into market design issues with our energy-only market. No one will build unless he can get a rate of return, and there has not been one to date. There has actually been a negative rate of return as is apparent from the retirements and bankruptcies. There are several prominent bankruptcies currently in the Texas market.

I think this summer is going to be when things start to change. We have said that almost every summer, but this year already feels different.

You start to get scarcity pricing once the operating reserve demand curve hits around 2,700 to 3,000 megawatts. When you have 4,000 or 5,000 megawatts of wind on the system over peak, it is nearly impossible to get any kind of scarcity pricing. That is where the problem lies. How to rectify that is one of the things we are going to have to address.

So what happens this summer? If we get through this summer with a 9% reserve margin, which is about where we are going to be when we hit the summer and scarcity is not factored into pricing the way the market expects, then that will be a problem. That is why several of us on the generator side, and some on the load side, are advocating for changes in the operating reserve demand curve to where it will add some additional revenues and change the slope of the curve for the summer.

MS. BARROW: Bob Helton, earlier this month there was actually a record set in ERCOT with an all-time winter peak demand. Did that lead to scarcity pricing? Why or why not?

MR. HELTON: Not really. Scarcity pricing turns on the level of reserves and the way the curve is shaped. When you have high wind, it adds another 4,000 to 5,000 megawatts to the system, and there is no scarcity. That is the problem.

MR. SMITH: The scarcity was limited. There were a few hours of scarcity pricing. In south Texas, you saw several hours of $3,000 prices, and you saw an hour of $1,500 here and $600 there. That kind of scarcity pricing for that duration is not going to cause anyone to build a new power plant. There does not appear to be any interest in base-load generation in ERCOT. So when you ask what kind of generation will replace the retired coal plants, I think wind will continue to be built. I think we will see more wind than anything else.

There is a growing queue for solar. There are about a couple thousand megawatts of solar in the interconnection queue that posted security for the next couple years. There are probably about 13,000 megawatts of solar that are under evaluation. As far as gas-fired generation, until people have confidence that they will see the kind scarcity necessary to get a rate of return, I do not think you will see anything built. Karl Dahlstrom may disagree.

MR. DAHLSTROM: I think there is a clear line of sight to scarcity pricing in ERCOT based on the fundamentals. We had it just yesterday. A weather event triggered it, but this shows how delicate the reserves are. We believe that there is funding to build low-cost gas peakers.

MR. HELTON: The average price last year was somewhere around $26 a megawatt hour. That was the energy price. That is the average price 24/7, and the ancillary service prices were about $1.07. That creates some problems for you. I hope that we do get to scarcity pricing, because we need it. We need the market to be able to function without brownouts and blackouts that can happen with reserve margins at 9%.

MR. SMITH: The fundamentals suggest we should be building, but every time we hit an all-time peak load, we have record-high winds. The knock on wind is supposed to be that it does not blow during peak hours, but when ERCOT has had summer peaks, the wind has been blowing like crazy. We have not seen the kind of scarcity pricing that we would have expected given our load shape.

MS. BARROW: Diving deeper into the effect of wind, let's bring up the elephant in the room. It is not an elephant, it is a panda. Panda Energy Partners sued ERCOT last year charging that misleading and faulty data in ERCOT's capacity, demand and reserve reports caused it to invest $2.2 billion in three merchant gas plants that eventually lost money. So talking about wind and renewables, Kevin Smith, how does / *continued page 38*

IN OTHER NEWS

The Conservation Law Foundation is challenging the action in the Maine superior court. It argues that the governor cannot unilaterally override a 2004 statute — the Maine Wind Energy Act — that provides for expedited permitting of wind farms.

LePage has asked the state legislature to amend the law to limit expedited permitting to certain remote locations in Aristook County in northern Maine.

COMMUNITY CHOICE AGGREGATORS and rooftop solar took about 25% of the retail load away from investor-owned utilities in California in 2017.

A CCA is a legal entity that buys electricity for local residents. Eight California counties have them currently. The oldest was formed in 2010. Another 12 are expected to be formed in 2018.

California assigns retail customers to CCAs by default unless they choose another electricity supplier. The staff of the California Public Utilities Commission estimates that as much as 85% of the electricity load will have shifted away from the utilities to CCAs and other suppliers by the mid-2020s.

At least six other US states now also allow CCAs. They are expected to be significant outlet for renewable energy projects over the next few years. For example, Peninsula Clean Energy, a CCA in San Mateo County, California, has signed at least nine long-term power purchase agreements to buy 550 megawatts of renewable energy. Marin Clean Energy gets more than a half of its power from renewables.

At least two 100-megawatt solar projects have been financed on the basis of power contracts with California CCAs, and a wind project is currently in the market. In the first of the two solar projects to reach financing, the lenders set up shadow credit metrics. If performance dips below these metrics, then cash is swept to repay the debt more quickly.

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ERCOT calculate reserve margins given renewables, and is it a rational methodology?

MR. SMITH: Around 2012 through 2014, ERCOT would apply an 8% to 9% capacity factor for wind. Then ERCOT changed to a methodology where it would look at the top 20 hours of peak load seasonally, both summer and winter, look at each wind farm's output across those peaks and then average that. It would average back to 2009, if the wind farm was operating then, to come up with an average.

Texas is the only organized electricity market in the United States with growing demand for electricity.

I think that is a fairly rational way of applying a capacity factor to wind. It takes into consideration location. The capacity factor for coastal wind is significantly higher across the summer peak than the panhandle west Texas wind, so I think you see around a 50% to 54% summer capacity factor for coastal wind, which is actually quite high.

MR. HELTON: The inland capacity factor in west Texas is about 18%. It took us a long time to get there. I think that is the right way to do it. No forecast is completely accurate.

Reserve Margin

MS. BARROW: The projected reserve margin for this summer according to ERCOT is 9.3%. ERCOT's target is 13.75%. What happens if the reserve margin goes even lower? Would there be a potential NERC violation?

MR. HELTON: I prefer to let ERCOT and NERC fight that one out. This summer, we will see whether the commission and the legislature have the intestinal fortitude to let an energy-only market work.

When you get to 9%, you would hope to see scarcity pricing to send the right price signals. There is a standing joke in Texas that we are always just one outage away from a capacity market. Blackouts and brownouts are possible with a 9% reserve margin.

MR. SMITH: To the point about intestinal fortitude, the commission has said publicly that it needs to educate the legislature before the summer about what to expect with an energy-only market.

MR. DAHLSTROM: ERCOT has benefited from an energy-only market for a long time with low power prices. The market was supposed to be one where scarcity price events create an incentive to build more generation. We think there are a lot of Milton Friedman fans in ERCOT that will allow the market incentives to work. The legislature will take some heat from the voters if prices spike. We understand that the PUC is leaning toward letting the market work and continuing with an energy-only market, but you guys are closer to it than I am.

MR. HELTON: All indications point to that.

MR. SMITH: When wind capacity margins were low in 2012, NERC sent ERCOT a letter expressing concern. NERC said it could not order NERC to build capacity or transmission, but NERC is responsible for the reliability of the bulk power system, and it had a responsibility to notify those in charge.

That started a discussion about capacity markets. The customers were not for it. The generators were. Ultimately, the PUC did nothing. The perspective in ERCOT has been that if it is not broken, don't fix it. When people talk about parts of it being broken, the response is power prices are low and that is what we want.

The customers have enjoyed the benefits of low power prices, and the generators have been challenged by them. It is a political hot potato to move to a capacity market. We probably will not see such a move until something goes seriously wrong. Maybe we start with a capacity obligation on load-serving entities.

We have a bifurcated market where 25% of the load is served by vertically-integrated utilities, municipal utilities and coops, and 75% of the load is competitive under one-to-three-year contracts. The municipal utilities and electric cooperatives have integrated resource plans and plan accordingly. The retail providers have short-term contracts, and it is a challenge for them to go out and make investments in steel.

Storage

MS. BARROW: Let's take this in a different direction. Karl Dahlstrom, Halyard has 100 megawatts of battery storage under development. Can you tell us more about that, and what makes those projects economic?

MR. DAHLSTROM: The projects are not economic today. We believe in flexible generation to help support the intermittent nature of renewables. We believe battery storage will eventually have a strong place in ERCOT. There is no place for it today. We are developing storage to get ahead of the curve and are closely watching the price of energy storage come down until a point, in the next few years, when it will make economic sense. We believe it makes sense to combine storage with the natural gas peakers we plan to build to help balance out VARS to support the grid as well as provide capacity.

MS. BARROW: Does anyone else on the panel have views about the potential for storage in ERCOT?

MR. SMITH: Everybody knows the issue with storage is the economics. It is just a matter of when. The economics will work first in the panhandle and west Texas. In the north zone in 2017, there were about 320 hours of negative prices in the first 11 months of 2017.

MR. HELTON: I have a different view because these guys are thinking about utility-scale storage, and I think the greater opportunity for storage may be behind the customer meter. Batteries will allow a move to virtual transmission. This will also spare the utilities from having to make the investment and then recover it from ratepayers. The ratepayers, or third-party actors, can pay for storage directly.

Let's do that on the distribution system. You can open up to some degree the distribution system planning and, as a competitor, I can offer up storage units as a solution to transmission constraints. I will sign a PPA with you to fix your problem. Only 20% of the battery is needed for that function. I can take the rest of the battery and bid the storage capacity in the competitive market.

The market is not open for this type of play today. We need to do some design changes to get there. We have to do system mapping down to the distribution system level. We are working currently to do that, but we are talking a few years still before this will be a reality.

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NEW PARTNERSHIP AUDIT RULES take effect in 2018.

Partnerships are not subject to US income taxes. However, the IRS is tired of chasing after partners for back taxes on their shares of partnership income. Some partnerships have as many as 10,000 partners. Therefore, starting this year, any back tax assessments imposed after an IRS audit will be collected from the partnership directly.

Most partnerships have a range of options, including electing out so that taxes are assessed on partners directly. This option may be used by partnerships with 100 or fewer partners, but it depends on the types of partners.

The IRS said in final regulations in December that partnerships cannot elect out of the new partnership audit rules if any of the partners is a partnership, disregarded entity or a foreign entity (unless the foreign entity is a corporation for US tax purposes).

Many partnerships are expected to choose a different, "push-out" election instead to leave audits at the partnership level, but push out any back tax assessments to persons who were partners in the year under audit.

Many partnership agreements need to be amended before year end to update the section on handling tax audits. Even recent partnership agreements often punted on the various choices while waiting for the IRS to fill in more detail in regulations about how the new rules will work. (For a more complete discussion of the subject, see "US Partnerships Get a Makeover" in the November 2015 *NewsWire*.)

INCURRED COSTS under the 5% test for starting construction may have to be reduced by any credit or discount the developer is given against a future turbine or other equipment order, depending on the facts.

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Solar

MS. BARROW: Let's talk about the potential for solar in ERCOT. There were 1,800 megawatts of installed solar capacity in ERCOT at the end of 2017, placing Texas seventh among the states. Kevin Smith, how rapidly will the solar market grow?

MR. SMITH: The best opportunity for utility-scale solar is in west Texas. The challenge is transmission. There is lots of cheap land in the west, and there is better irradiance. But the electricity load is in the east, so you need transmission. This makes it a challenge.

Thus, we are seeing smaller-scale solar projects — less than 50 megawatts in size — being built closer to load and being connected at the distribution level. One of the benefits of connecting at the distribution level is it avoids congestion.

MR. HELTON: We are seeing utilities put out requests for proposals for solar of five megawatts in one case and 15 megawatts in another. These are small projects that will connect to distribution lines.

There is an interesting wrinkle in the way we price and pay for transmission in ERCOT. Demand charges are based on your percentage of four coincidental peaks during the summer. If a commercial or industrial customer installs a one-megawatt solar facility with storage, that does not count as generation. It counts as negative load and lowers the four coincidental peaks and, in turn, lowers the demand charges. We tend to see these types of plays mainly in areas served by municipal utilities and electric cooperatives.

MR. DAHLSTROM: I agree. I think the largest challenges are grid congestion and lack of PPAs.

Offtake Options

MS. BARROW: How hard is it to get a PPA today in ERCOT for any type of generation?

MR. DAHLSTROM: It depends on who is responsible for the reserve margins. The utilities have benefited from an energy-only market where they had very low prices. They have been signing two-year strips to cover their current peak season and a future peak season and avoiding having to take a long-term view on the market.

They have done well to date with this strategy. It will take one or more significant scarcity price events for utilities to commit to a long-term power purchase agreement and take a view on the future. Until that happens, I do not see a lot of opportunities for PPAs. We will see whether that changes by this coming fall.

MR. HELTON: I agree. There are no long-term PPAs to be had in the current market. The few utilities that feel the need to take a view on future prices would rather own the generating facilities than sign long-term power purchase agreements.

For developers, that means they do better currently to offer to build and transfer projects to utilities than to count on PPAs.

MS. BARROW: How easy or difficult is it to arrange a hedge in ERCOT?

MR. DAHLSTROM: Physical hedges in the form of heat-rate call options and revenue puts are available from financial parties. They are short-term contracts in the five- to 10-year range. Those are readily available. It just comes down to the price. When looking at the price, there are two things to consider: how much will a letter of credit cost to secure your obligations, and how much value are you getting from the hedge?

We believe that it makes sense to secure a heat-rate call option for at least a portion of the output to help attract lower-cost debt.

MR. SMITH: There is a pretty robust market for hedges. Hedges price at a hub. Such a hedge may or may not work for you depending on how far the generating facility is from the hub and what type of resource it is.

The state is expected to have a 9.3% reserve margin by this summer, which is below the 13.75% target.

Transmission

MS. BARROW: Several of you have mentioned transmission issues. What has been the effect of CREZ — competitive renewable energy zones — on transmission issues in ERCOT?

MR. SMITH: CREZ has lowered the overall price of wholesale energy because it facilitated the renewables boom in west Texas and the Texas panhandle. It is unclear to what extent it has affected retail prices.

CREZ has also contributed to potential price volatility associated with system deviations. CREZ has helped renewables displace thermal generation in the day-ahead market, which leads to fewer dispatchable resources on line to respond to system deviations, like load forecast error or unit trips, and that leads to more volatility in prices.

MR. HELTON. Before CREZ, everything was bottled up. You used to have negative prices all the time in the west zone. Curtailments due to congestion were common. CREZ reduced, but did not eliminate, both the frequency and amount of negative pricing, but such pricing then spread to the rest of ERCOT.

Now you have a lot more ERCOT-wide negative pricing, albeit not as bad as the $14 to $15 range. Maybe it is $2 to $4.

MR. DAHLSTROM: CREZ has brought low-priced wind to where the load is on the eastern side of the state, and this is putting pressure on base-load plants to cover their fixed costs where they probably did not have such pressure before.

MR. HELTON: The question now becomes how to take care of base-load units in a zero-marginal-cost world. That is where we are headed in ERCOT. We need these units because of low reserve margins, but we have to find a way to make it economic for such plants to remain on the margin. Perhaps the return has to come through ancillary service capacity payments. This is part of the fallout from CREZ.

MS. BARROW: Somewhat related to transmission issues, do you see the potential for any new transmission lines to be built into Mexico?

MR. HELTON: Asynchronously connecting ERCOT to Mexico will not happen. It would probably give the Federal Energy Regulatory Commission jurisdiction over ERCOT. That is considered a sacrilege in Texas. The Baja peninsula is already asynchronously connected to California and Arizona. Connecting Texas to Mexico would give Texas power a path to markets in those two states and give FERC jurisdiction over the Texas market.

While you will not see that, what you may see is switchable units. Mexico has a very good capacity market.

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This is the upshot from a memo that was made public in January by the IRS national office to an IRS agent in the field. The memo is FAA 20180101F.

The memo discusses a fuel rewards program that a grocery chain offers customers. The grocery chain was under audit.

Certain products on store shelves are tagged to give rewards. A customer buying these products receives credit on a fuel rewards card that the customer can then redeem for gasoline at a participating service station. The customer puts the rewards card in the fuel pump. The pump meters out gasoline until the limit on the card is reached. The grocery chain pays participating service stations for the gasoline after subtracting a discount.

At issue in the audit is when the expected costs to buy the fuel accrue so that the grocery chain can deduct them.

The cost of a reward in the form of a discount against a future purchase does not accrue until the customer makes the actual purchase because there is no cost to the grocery chain unless the customer makes the other purchase.

By contrast, the cost of a reward where the customer is essentially given a receipt that allows him to pick up a product at another location accrues immediately. The IRS said the grocery chain bought fuel from a third party and has the customer pick it up at another location.

The memo is a reminder to developers counting costs under the 5% test to make sure the amounts being counted are for the equipment being purchased and not for something else.

Developers of wind, solar, geothermal, biomass, fuel cell and other projects face deadlines to start construction. One way to start construction is to incur at least 5% of the project cost before the deadline. Costs do not count before they accrue for tax purposes.

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Mexico does not really accept any switchable units in the capacity market currently because Mexico is unsure whether the units will be there when needed, especially given the high potential for emergency events in Texas.

If that can be worked through, and there was a bill in the last legislature to do that, to the point where you can build and offer a switchable unit in the Mexican market, including during an ERCOT emergency, in exchange for a capacity payment, then you will see a lot of new development along the southern border into Mexico with switchable units that can earn a capacity payment in Mexico while still earning energy payments in ERCOT.

MR. SMITH: There are currently three DC-tie lines from Texas into Mexico. All of those are in rate base. I would be surprised to see another one put into rate base.

MR. DAHLSTROM: My understanding is that FERC sent a letter that was a shot across the bow suggesting that a cross-border transmission line would create FERC jurisdiction. I think Texas enjoys having its own grid and retaining the option to secede from the Union.

MR. HELTON: The shot across the bow is leading to a protocol revision that that will allow ERCOT to disconnect the existing DC tie lines preemptively if necessary to prevent Texas from becoming subject to FERC jurisdiction.

MS. BARROW: It sounds like FERC staff and ERCOT staff just need to sit down and have a cup of coffee.

MR. HELTON: There are some conversations on how that might take place and on the potential to get waivers. There are two DC tie lines that go north from Texas into neighboring US states, and they were given exemptions when they were built. The trouble with the ones into Mexico is they don't have exemptions. There will be discussions about whether they can be given exemptions. ◎

Energy Storage in Latin America and the Caribbean

by Brian Greene, Deanne Barrow and Ignacio Alfaro, in Washington, and Monica Borda in Mexico City

Latin America is in the midst of a dramatic energy transformation.

Region wide, countries are rapidly transitioning from fuel oil and hydroelectricity as the main power sources to a more diverse energy mix, including natural gas, solar and wind.

In Brazil, Colombia, Panama, Uruguay, Chile and elsewhere, LNG import terminals have been built or are planned. Solar and wind have exploded in countries such as Chile, Honduras, Peru, Brazil and most recently Argentina, where the RENOVAR program has awarded 2,400 megawatts of projects.

Although its current impact is minimal, energy storage — and specifically battery storage — will play key a role in this transformation. In part, the increased importance of battery storage will be inevitable as the costs of batteries decrease. However, the extent of the growth of battery storage — and its effect on market penetration of renewable energy, rural electrification and disaster relief — will depend on both the extent of the decrease in battery storage costs and the development of regulatory regimes that reward the services that storage is capable of providing.

Energy storage projects are either in operation or planned in various Latin American countries.

These projects provide an indication of what energy storage in Latin America may look like in the future, as well as a tool for regulators and developers to understand how energy storage projects can provide valuable services to the grid. They also provide insight into how energy storage is being used across disparate markets in Latin America: in countries with large, interconnected grids, for off-grid, rural electrification and on island grids.

Below are some of the planned and operational energy storage projects in the region.

Energy storage projects are either in operation or planned in various Latin American countries.

Argentina

Argentina has had pumped-storage hydropower since the 1980s. The Los Reyunos power plant in Argentina has an installed capacity of 224 megawatts and has been generating electricity since 1983. Using the same technology but at a larger scale, the Rio Grande hydroelectric complex was built in 1986. It has an installed capacity of 750 megawatts comprised of four turbines of 187.5-MW each.

Pumped-storage hydropower is a mature technology that relies on moving water from one reservoir to another in order to generate electricity. When energy is cheaper during off-peak hours, electricity is used to pump water from one reservoir located at a lower altitude to another reservoir located at a higher altitude. Later, when electricity is in high demand and more expensive during peak hours, the water from the higher reservoir is released to the lower reservoir, causing electricity to be generated when the water passes through a turbine or set of turbines.

Thus, this technology is dependent on the presence of specific conditions. The geography of the location must allow the construction of two interconnected reservoirs located at different altitudes so the water can fall from one to the other at a speed significant enough to generate electricity through the turbines.

Chile

Chile, by regulations, remunerates generators for providing frequency regulation and penalize them if performance is poor.

These regulations were in part a response to intermittency issues caused by the growing number of solar and wind projects.

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TRANSFER PRICING ISSUES led to being whipsawed on foreign tax credits.

Coca-Cola operates in more than 200 countries and collects royalties from its foreign branches and subsidiaries for use of its drinks formulas, brand and other intellectual property.

It worked out an agreement with the IRS about the appropriate level of royalty payments to settle an audit of its 1987 to 1995 tax returns. The agreement was that Coca-Cola licensees in other countries would pay the US parent company royalties using a 10-50-50 formula where 10% of the gross sales revenue is treated as a normal return to the licensee and the rest of the revenue is split evenly between the licensee and the US parent, with the part going to the US parent paid in the form of a royalty.

The closing agreement expired in 1995, but Coca-Cola continued to use it for transfer pricing, and the IRS accepted it, for the next 11 years.

Meanwhile, Mexico adopted an arm's-length standard in 1997 for payments between affiliates. Coca-Cola and the Mexican government agreed on the same formula that Coca-Cola had worked out with the IRS. Mexico kept renewing the transfer price agreement through 2004. Coca-Cola continued to use it after that on the advice of Mexican counsel.

The IRS selected the company's 2007 to 2009 tax returns for audit in 2011 and made an adjustment in 2015. It said Coca-Cola should have paid a higher royalty to the US parent.

Because Coca-Cola did business in Mexico directly (meaning through a branch office of the US parent), there was no direct effect on its US income. The effect was in Mexico where the IRS said the company reported too much income on its tax returns because it should have been deducting higher royalty payments.

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The quality services technical regulations adopted in 2015 require all generating companies interconnected to the grid to meet certain standards of security and quality services to ensure the grid operates at a near-constant frequency of 50 Hz (slightly lower in contingency scenarios). If a generating facility displays poor performance on frequency regulation, then the Superintendent of Fuels and Electricity can impose penalties ranging from US$75 to US$9,000,000.

Other regulations that complement the quality services technical regulations require frequency regulation to be remunerated as part of ancillary services that any generation company interconnected to the grid can provide.

AES Gener (a subsidiary of The AES Corporation) owns 52 MW of storage capacity in operation in Chile through three separate lithium battery arrays. Each of the battery arrays is tied to one of AES Gener's thermal plants. The AES Gener storage projects help AES Gener's thermal plants comply with spinning reserve requirements and increase power generation from the plants because the spinning reserve requirement is met by the batteries.

The 20-MW Angamos array reportedly allows AES Gener to increase the power generation of the Mejillones 544-MW thermal plant by up to 4%. Although the Chilean regulations are not specifically geared toward energy storage, the ability of energy storage to provide frequency regulation through spinning reserve is a natural fit.

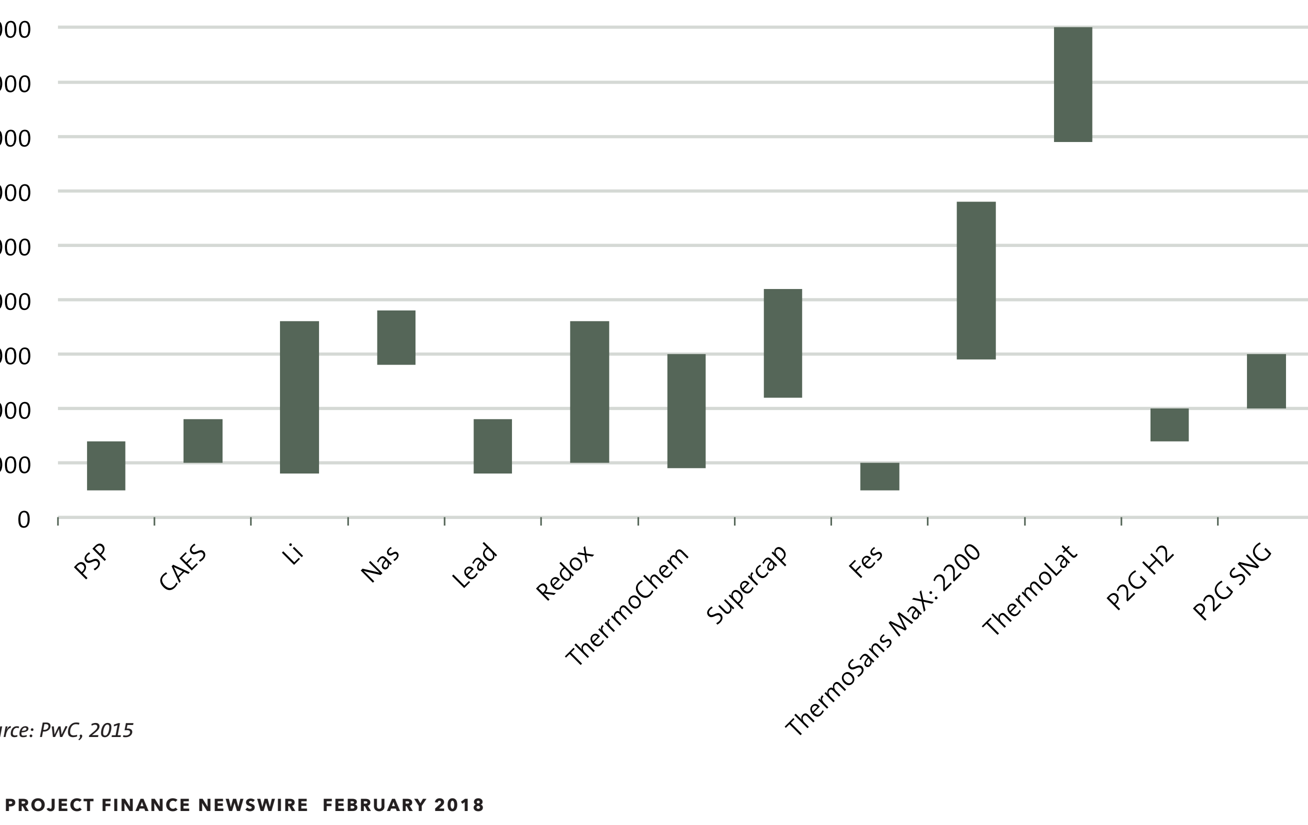
Dominican Republic

Like Chile, the Dominican Republic has also adopted regulations that provide a favorable climate for energy storage through the remuneration of frequency regulation services.

The groundwork was laid in 2001 with the passage of a General Electricity Law (No. 125-01), followed a year later by an "application regulation" (adopted through Presidential Decree No. 555-02), that established a requirement for all generators to provide frequency regulation service to the grid and empowered the Superintendent of Electricity to adopt an incentive. The amount of the incentive is calculated from a formula set yearly by the Superintendent of Electricity, with the current base incentive for 2018 being US$9.65 a megawatt hour

In September 2017, the Dominican Republic took a near direct hit from hurricanes Irma and Maria, forcing 40% and 55% of the

Figure 1: Specific investment costs for the 2015 study period (€_2014)
Recent specific cumulative costs



Source: PwC, 2015

nation's power plants off line, respectively. However, the Dominican grid itself remained operational, thanks in part to frequency regulation services provided by two AES-owned 10-MW lithium ion arrays. The role of the batteries in maintaining the Dominican grid is being studied by other Caribbean islands, including Jamaica and Puerto Rico.

Mexico

In Mexico, General Electric has announced five energy storage projects to be developed, with a projected capital cost of around US$5 million each. These energy storage projects will be used to facilitate the incorporation of solar and wind projects into the electric grid.

In 2016, the Mexican Energy Regulatory Commission (Comisión Reguladora de Energía or CRE) passed a resolution adopting criteria for efficiency, quality, reliability, continuity, safety and sustainability of the national electricity system. This "grid code" requires regulators and operators to ensure the reliability of the grid, including through oversight of ancillary services such as frequency regulation.

The CRE launched a "Regulatory Program 2017" for the purpose of communicating to the industry its goal of creating a more transparent and predictable set of regulations for the energy sector in Mexico.

The Regulatory Program 2017 includes a document titled "General Administrative Provisions on Energy Storage" (Disposiciones Administrativas de Carácter General en Materia de Almacenamiento de Energía Eléctrica) that signals that CRE has started preliminary regulatory work on stage one. An initial draft of the administrative provisions is expected to be released later this year.

Jamaica

Increased penetration of renewable energy on the grid has on occasion led to frequency imbalances, load disconnections and blackouts.

To address these problems, the Jamaica Public Service Company held a bidding process for energy storage during 2017. A hybrid storage solution was awarded the bid, consisting of lithium batteries and high-low speed flywheels of approximately 24.5 MW aggregate capacity. The main goal of the project is to provide grid stability and ensure power quality whenever energy from renewable energy sources on the island varies significantly.

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The IRS disallowed $43.5 to $50 million in foreign tax credits in each of the three years for taxes that the IRS said Coca-Cola overpaid in Mexico due to failure to deduct the right amount of royalty payments.

This made the extra taxes Coca-Cola paid in Mexico voluntary taxes, the IRS said. Voluntary tax payments cannot be claimed as a foreign tax credit in the United States.

Coca-Cola asked both governments to work out the proper royalty using a process called a competent authority proceeding. The IRS declined to engage with Mexico on the issue.

The company and the IRS are locked in a larger dispute over $3.3 billion in foreign tax credits that the IRS disallowed for the three years in question on account of adjustments that the IRS made to transfer price payments from Coca-Cola affiliates in Brazil, Chile, Costa Rica, Egypt, Ireland, Mexico and Swaziland. That case goes to trial on March 5.

In the meantime, the court sided with Coca-Cola in December on the narrow question whether any part of the Mexican taxes the company paid were voluntary. The court said the company had exhausted all practical remedies to reduce its Mexican tax bill. The only practical remedy is the competent authority process in which the IRS refused to participate.

The case is *Coca-Cola Company v. Commissioner*.

The company complained to the US Tax Court in mid-February about the government's plan to call 121 witnesses.

PLEDGES of interests in Delaware limited liability companies are being mishandled in some transactions.

Lenders require borrowers to pledge shares or other interests in any company they own that is a source of revenue to repay the loan.

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Energy Storage

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The project has attracted a commitment of US$21 million from the Jamaica Public Service Company and is aligned with the regulator's policy commitment to promote renewable energy. The project is expected to be operational by the third quarter of 2018 and will be a first of its kind in the Caribbean.

Rural Electrification

Kingo Energy provides renewable energy services in off-grid, rural areas of Latin America, where the customer pre-pays for the electricity and does not pay any upfront costs for installation of the system.

Kingo retains ownership of the equipment, consisting of rooftop solar systems connected to a battery, and a variety of add-on products; Kingo also provides a service warranty for the life of the customer's contract.

The customer signs a contract agreeing to use the system for a pre-established period of time each month, and then has the choice to make daily, weekly or monthly pre-payments for electricity.

Kingo earns a profit based on the resale of power. In rural, off-grid areas, families tend to use the most expensive energy substitutes available, which are candles, kerosene, and diesel.

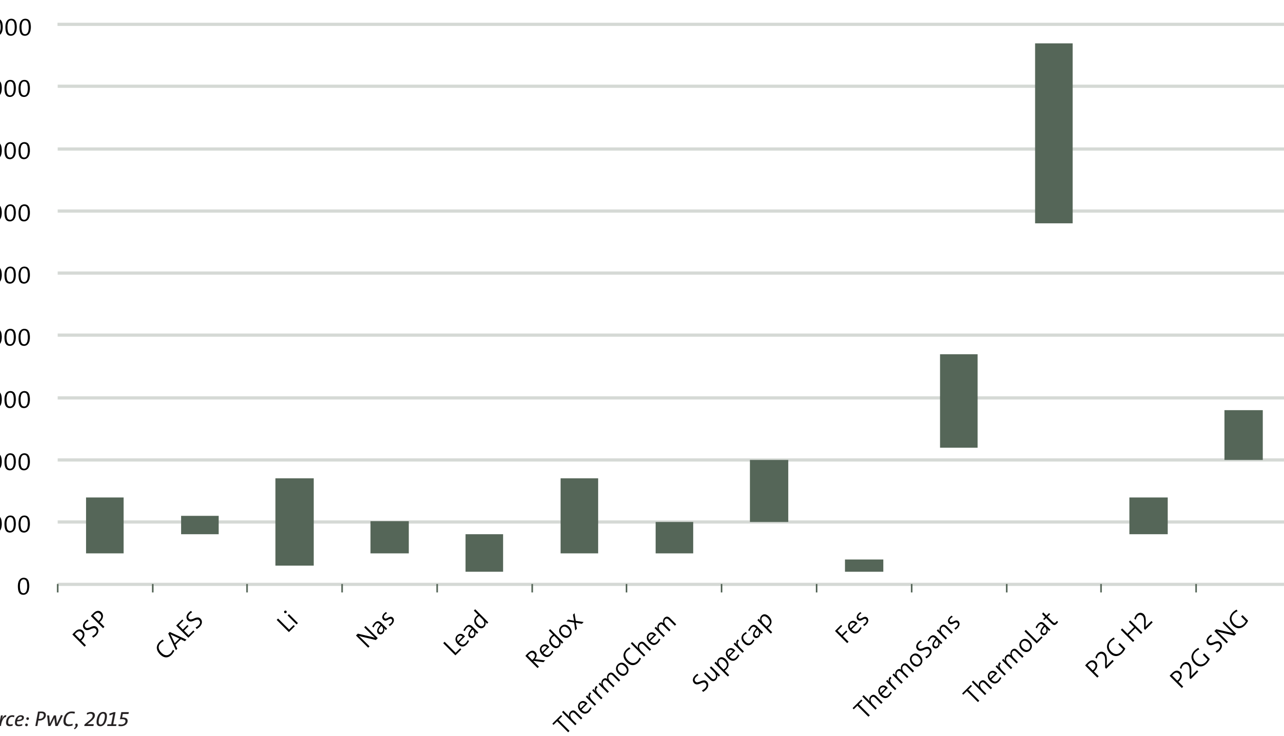
Challenges to Deploying Storage

High costs are the most significant barrier to energy storage deployment not only in Latin America, but also worldwide.

Technological advances are expected to drive down costs in the near future, but reductions will not be uniform across all technologies. Figures 1 and 2 compare installation costs for energy storage capacity per installed discharging capacity in euros per kilowatt for different kinds of energy storage technologies in 2015 and projections for 2030.

Mature technologies, such as pumped hydropower storage, show less significant cost reductions than less mature technologies such as batteries. Costs of lithium-ion batteries in particular

Figure 2: Specific investment costs, 2030 (€_2014)
Specific cumulative investment costs 2030



Source: PwC, 2015

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have declined sharply in recent years due in large part to the growing market for electric vehicles and consumer electronics. According to McKinsey & Co., the cost of lithium-ion modules has fallen more than 70% since 2010, from around US$1,000 a kWh to below $230 a kWh in 2016. IHS Markit expects costs to drop below $200 a kWh by 2019.

Despite rapidly declining costs, battery storage remains a relatively expensive technology. This is even true at this time for island markets that rely predominantly on oil for electricity generation. According to a recent report from GTM assessing the economics of various alternatives to oil, a solar PV system paired with a battery storage system currently has the highest levelized cost of energy or LCOE, taking into account the cost of the systems as well as construction costs for infrastructure. However, by 2025 things change, as costs are projected to come down enough that solar plus storage will be competitive with diesel (see Figure 3).

The economics for renewable energy coupled with energy storage are strongest in small off-grid towns and island countries in Latin America and the Caribbean due to the high avoided cost of conventional generation.

A team of economists at the Inter-American Development Bank assessed the relative economics of renewable energy paired with energy storage in a small off-grid town (Colombia), an island country (Barbados) and a country with a large, inter-connected grid (Mexico). In all cases, energy storage supported a significant increase in renewables as a percentage of total generation by counteracting the intermittency of renewables through the addition of backup capacity and the ability to store lower-cost renewable energy to discharge at a later time.

In the small off-grid town and the small island country case studies, combining energy storage with renewable energy increased the share of renewable energy in total generation more than renewable energy without energy storage, without increasing the cost of electricity.

This result is explained by the high avoided cost of conventional generation in small off-grid towns and island countries. The value of the savings accrued from using additional renewable energy to generate electricity (instead of conventional generation) was larger than the cost of installing and maintaining the energy storage system.

The economics are more challenging for large countries with organized electricity markets.

Combining renewable energy with energy storage did not result in a reduction in energy prices in / continued page 48

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The owners of the borrower must also pledge their interests in the borrower to give the lenders more options for how to foreclose on collateral if the borrower defaults on the loan. These pledges become part of the collateral package securing the loan.

Delaware limited liability companies are the most common form of US business entity used in project finance transactions. Owners of LLCs are called "members."

Pledge agreements usually recite that the economic and voting rights and member status are being pledged, but this is not enough for an effective pledge, says Christine Brozynski with Norton Rose Fulbright in New York. Rather, the operating agreement of the LLC being pledged must be amended to say that the voting rights and member status are assignable, notwithstanding anything to the contrary in the Delaware LLC statute.

"The reason for this is the Delaware statute specifically states that although economic rights are freely assignable, control rights and member status are not, unless the LLC agreement expressly permits such an assignment or the assignment is otherwise approved by all the members other than the one making the pledge," Brozynski said.

The Uniform Commercial Code does not override the laws of the state of incorporation, meaning any restrictions on assignment under Delaware law cannot be overridden in the pledge agreement. Due to some additional quirks under Delaware law, it is best practice to amend the LLC agreement even when the pledge entity has only a single owner.

CO2 ALLOWANCES that forestry companies receive for preserving trees are not "real property" for REIT purposes, the IRS said.

The IRS revoked a private letter ruling that said the opposite. It made the announcement in December in Private Letter Ruling / continued page 49

Energy Storage

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the Mexico case study. For that to change, either the cost of conventional peak generation (largely a function of natural gas prices) would need to rise or the costs of battery storage would need to decrease.

Projects on islands will advance first since they displace high-cost fuel oil.

Pumped hydropower storage is different from other forms of energy storage in that it is a mature technology — so costs are unlikely to decrease significantly — but projects may only be built in places that are geographically suited. Pumped hydropower storage projects also tend to be large, capital-intensive projects. Thus, while specific projects may be built — the proposed Valhalla project in Chile is an example — pumped hydropower storage is not expected to be used across the region in the same way that is expected for battery storage.

Predicting market trends and technological processes is no easy task and not the purpose of this article, but an analogous example that can be interesting to consider in this case is solar panels and their prices. In 1977, the price for a solar panel was US$76.67 a watt, a prohibitively high price that impeded widespread adoption of the technology. Solar panel prices plummeted to their current price of about 46¢ a watt more quickly than anyone expected. If a similar decrease in price happens to batteries — catalyzed by electric vehicle adoption — energy storage could be the dominant player in the market sooner than analysts predict.

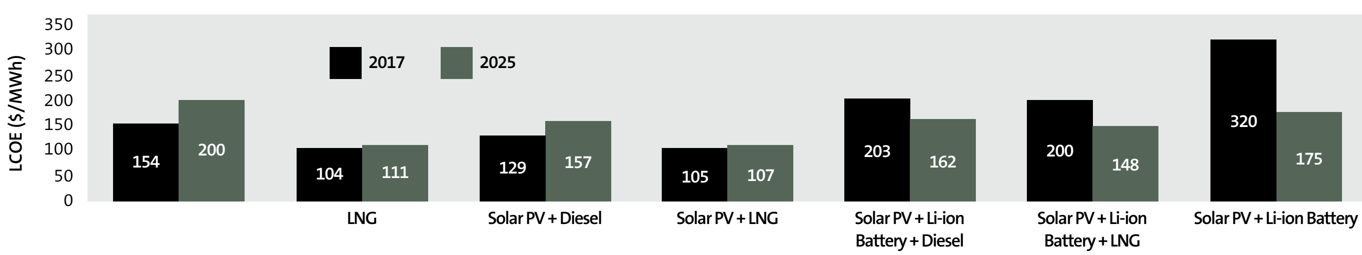
Regulatory Frameworks

Regulatory and policy frameworks for energy storage are undeveloped in Latin America and the Caribbean.

However, pockets of favorable regulatory climates do exist, and developers have been focusing their activities on those countries. For example, storage developers are using the performance of batteries in the Dominican Republic to make the case to regulators in other island countries of the necessity of battery storage systems to protect against natural disasters.

As already noted, Chile and the Dominican Republic have adopted regulations that provide a favorable climate for energy storage through the remuneration of frequency regulation services. The projects built to earn revenue from ancillary services provide key lessons and early success stories for the region. The Rocky Mountain Institute has identified 13 fundamental services that energy storage can provide when deployed behind the meter. The 13 are various services for host customers, utilities and transmission providers, ranging from energy arbitrage to backup power, frequency regulation, voltage support, transmission congestion relief and demand charge reduction, among

Figure 3: LCOE of New Island Market Power Supply, 2017 vs. 2025



Source: GTM Research, Wood Mackenzie

others. Regulatory regimes must be updated to provide value for these services.

Rural electrification programs are less likely to be influenced by the regulatory regime, but will be heavily dependent on government support and non-governmental organizations. However, the economic case is most compelling for rural electrification.

Financing

High costs and underdeveloped regulatory frameworks are dampening the ability of developers to get access to third-party, private-sector financing for energy storage projects in the region.

No project financings of energy storage projects in Latin America have been reported to date. Instead, developers are financing projects on balance sheet, while other projects have been limited to pilots, demonstrations and feasibility analyses supported by concessionary or grant financing from multilateral development banks like the Inter-American Development Bank.

Given the predominance of vertically integrated utilities in Latin America and the Caribbean, one financing model for energy storage that shows promise is build-own-transfer (BOT). Under this arrangement, the utility commissions the project to be built by an independent firm and the project is then transferred to the utility upon completion and put in the utility's rate base. Acquisition of the facilities rather than signing PPAs and buying the output provides the utility with the opportunity to add new assets to its rate base and earn a return on those assets.

Energy storage for rural electrification and on island grids in Latin America and the Caribbean will take off quickly. Such projects have the greatest shot at being economical due to the displacement of high-cost conventional fuel.

Energy storage in larger countries in the region will also occur, but projects will be deployed first for specific applications where a clear path to compensation exists. For instance, at some point, storage in large countries could be used for time-demand arbitrage for solar plants in the north of Chile if transmission issues still persist. The mix for large countries is likely to be renewables, plus storage, plus LNG. ◎

201751011. The revoked ruling is PLR 201123003.

The latest IRS action means that paper and timber companies organized as real estate investment trusts, or REITs, should not own such allowances directly. They should be held in a separate taxable REIT subsidiary.

A REIT is a corporation or trust whose units are publicly traded, but that is not subject to income taxes to the extent it distributes its income each year to its shareholders.

REITs must be careful to maintain the right asset and income mix. At least 75% of assets must be real estate, cash and government securities. At least 75% of annual income must be from real property, and at least 95% of income must be from real property plus dividends and interest.

The ruling dealt with a CO2 emissions trading program in a foreign country.

Trees capture carbon dioxide and later, when the trees are cut down, the CO2 is released.

Participation in the emissions trading program is mandatory for owners of older forests, but voluntary for owners of newer forests. Anyone participating receives one unit, or allowance, for each metric ton of CO2 captured by his trees. The units can be freely sold in the market. If the trees are later cut down, then the owner must turn in the number of units corresponding to the CO2 released. If he does not have enough, he must buy them on the open market. If the forest is sold, the units transfer with it.

The program operates in a way that discourages forestry companies from cutting down trees.

The IRS reached a number of complicated conclusions about the tax consequences of the program to forest owners in the latest ruling on the subject.

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Tax Equity Primer for Back-Levered Lenders

by Jim Berger and Amanda Rosenberg, in Los Angeles

Back-levered loans remain a core financing tool in the US renewable energy market. Because such loans are behind tax equity in the capital stack for a typical project, it is critical for back-leverage lenders to understand key concepts in the tax equity arrangements because the tax equity has first claim on the cash flow needed to repay both types of financing. Many of these issues affect the lenders directly. Others are important pieces of the overall financial model for the project that should be understood.

There are several important concepts.

A partnership flip is the most common form of tax equity financing. About 80% of tax equity deals in the solar market and 100% in the wind market take this form.

The concept is simple. The US government offers two tax incentives for renewable energy projects: accelerated depreciation and tax credits. In most cases, the tax benefits can be claimed only by the owner of a project. By becoming a partner in a partnership that owns the project, a tax equity investor can be allocated a disproportionate share of the tax benefits on a project.

In a typical partnership flip, the tax equity investor is allocated 99% of income, loss and tax credits until it reaches a target yield. After the tax equity investor hits its target return, the partnership "flips," meaning that the tax equity investor's share of income, loss and tax credits drops to 5%. Cash is distributed in a different ratio. The cash sharing ratio varies from one deal to the next. However, the project developer typically takes a majority of cash both before and after the flip. The tax equity investor's share of cash usually drops to 5% after the flip, although in some deals, it is as low as 2.5%.

The term "allocations" refers to how the income, loss and tax credits are shared by the partners. The word "distributions" refers to how cash is shared by the partners.

Lenders will be most concerned with cash distributions to the developer partner since back-levered debt is a loan to the developer partner against the future share of cash that partner expects to be distributed by the partnership. However, it is important for lenders to understand the allocations as well.

In some deals, the income, loss and tax credit allocations and cash distributions flip on different dates. However, in other deals, they flip on the same date (for example, the date that the tax equity investor hits its target yield). It is important for a lender to understand what triggers a flip in the cash sharing ratio and what might cause the flip date to vary from expectation.

There are different varieties of partnership flips, but most work as described.

The rest of this article assumes the tax equity partnership is a holding company that owns a special-purpose project company that owns a solar or wind project and the share of the tax equity investor in the project flips down once the investor reaches a target yield rather than on a fixed date.

Transfer of Control

The primary collateral backing the back-levered loan is a pledge of the partnership interest held by the developer partner and the cash distributions to that partner. If the loan is not repaid, the lenders can foreclose on these interests and step into the shoes of the developer partner (or assume ownership of the developer partner). The developer partner is almost always the managing member of the partnership and is responsible for day-to-day operation of the business.

However, there are usually significant restrictions on transferring the developer partner's interest with which a foreclosing lender must comply. These restrictions also often apply to indirect transfers (the transfer of the developer partner entity or even higher up the corporate structure). A "disposition" that is subject to change-of-control restrictions in the tax equity papers includes the transfer upon foreclosure (or in lieu of foreclosure) and any subsequent transfer of the developer partner interest or the developer partner entity.

A common restriction in existing tax equity deals is that the disposition cannot cause the tax equity partnership to terminate for tax purposes (often called a "technical termination"). A technical termination used to occur if there was a sale or exchange of 50% or more of the total interests in partnership capital and profits within a 12-month period. However, it no longer does. The new tax-cut bill that President Trump signed in late December 2017 eliminated the concept of technical terminations.

Other tax restrictions on the ability of a back-levered lender to foreclose include that the disposition cannot cause the partnership to turn into a corporation for tax purposes and cannot cause recapture of any tax credits claimed by the tax equity investor. It would be very unusual for these problems to arise. Some partnership agreements will permit a transfer that violates

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one or more of the transfer restrictions if the partner whose interest is transferred indemnifies the other partners for any harm.

If the lender forecloses, it may not be able to resell the interest to anyone buying electricity from the project. First, production tax credits, which are claimed on the electricity output from wind farms, can only be claimed on electricity sold to an unrelated person. A person, like a utility, that buys electricity and resells it immediately to its ratepayers is okay; the Internal Revenue Service ignores the intermediate sale. Second, the partnership will not be able to claim tax losses if it sells electricity to a partner or an affiliate of the partner.

Tax equity investors are agreeing to lower limits on cash sweeps to pay indemnities so that enough cash remains to pay debt service on back-levered loans.

More to the point, since the tax equity investor provided financing based on its belief that the developer was well placed to manage the wind farm, the investor will not be happy with a lender stepping into the role, and it may impose a time limit on how long the lender can hold the interest before transferring it to someone else, and it will require any subsequent transferee to meet net worth and experience tests. It will also want an experienced project operator in place in the interim while the lender is looking for someone to buy the developer's interest.

If the tax equity deal is being negotiated at the same time as the back-levered loan, then the lender may be able to negotiate an advance waiver of some of the standard transfer restrictions in the tax equity documents that limit the ability of the developer partner to transfer its interest (whether in or out of foreclosure). It is time consuming and costly to negotiate consents after a deal is signed, if the tax equity investor is even willing to make any changes to the transfer restrictions.

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First, the units themselves are not real property, the IRS said. Thus, holding them directly in a REIT makes it harder to maintain REIT status.

Second, the market value must be reported as income upon receipt. The IRS said the units are the equivalent of a payment for selling the government an easement over the forest. It is as if the owner sold an easement and the units are compensation.

However, since the units themselves are not real property, the income from any later sale of them is not income from real property.

MINOR MEMOS. Lenders are requiring that equity account for only 8% of the capital stack of a solar project rather than the more traditional 10%. The change is further evidence of the fierce competition among lenders this year for deals . . . . Insurance broker Aon reports that the tax insurance market now has the capacity to write policies of up to $1 billion. It says there are more than a dozen primary insurers willing to write such policies . . . . Bitcoin mining will use more electricity by 2020 than the entire world uses today if current trends continue, according to GTM Research. A block of 12.5 bitcoins is released every 10 minutes to the first person to solve a series of complicated math puzzles requiring major computing power. The number of coins released drops by half every four years. The total number of coins is capped at 21 million. The cap will be reached in 2140 . . . . The IRS treats bitcoins and other crypto-currencies like property. Investors must report gain or loss on the sale. However, Credit Karma Tax, a free on-line tax preparation service, reports that fewer than 100 of the 250,000 tax returns it has filed so far this year reported owning crypto-currency for tax purposes, a far smaller percentage than the 7% of Americans that are believed to own such currencies, and,

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Tax Equity

continued from page 1

Cash Sweeps

In a tax equity transaction, the developer makes a series of representations and agrees to various covenants and must indemnify the tax equity investor if the developer breaches any of these undertakings.

Common tax representations that can trigger an indemnity if incorrect may include that the partnership is using the right tax basis to calculate tax benefits and when the project was first put in service. Tax credits might also be lost if the project was not under construction by a deadline that has already passed. The developer may be asked to represent that it was under construction in time.

In the case where tax credits are disallowed or recaptured, there is likely to be a very large indemnity payment owed to the tax equity investor, and the developer may have to add a "tax gross up" by dividing the underlying loss by one minus the corporate income tax rate. There also could be substantial interest owed to the IRS.

The developer will have provided a guaranty to the tax equity investor to guarantee payment of indemnities.

If the developer and guarantor fail to pay the indemnity promptly, then the tax equity investor is allowed to sweep cash that would otherwise have been distributed to the developer partner to pay the indemnity. Since this is source of payment of debt service on the back-levered loan, it is a problem for the back-levered lender.

Some transactions limit the percentage of cash that can be swept: for example, to 75% or 50%. Some allow cash to be swept only above the cash needed to pay scheduled principal and interest on the back-levered debt. Others allow a full sweep of all cash available for distribution to the partners.

In some deals, tax insurance may be purchased to pay the indemnity and avoid a cash sweep.

In a growing number of deals, the tax equity papers set a target flip date and if the flip has not occurred by that date, the tax equity investor is allowed to sweep cash to get to the flip yield as quickly as possible.

A lender needs to build mechanisms into the credit agreement to protect it in situations where sponsor cash is being swept to the tax equity investor. A common protection measure is a cash diversion indemnity or guaranty in which the parent of the developer partner agrees to contribute to the developer partner, for the benefit of the lender, cash to cover any cash diversions, which include, among other things, cash swept to the tax equity investor. Other protections that a lender might request include a cash reserve or other credit facility that can be accessed to make the lender whole.

Tax Distributions

Partnership flip deals almost always have "absorption" issues. Each partner has a capital account, which is a metric for tracking what the partner put into the partnership and is allowed to take out.

Since the tax equity investor will not have paid the full cost of the project for a fractional interest in the partnership, its capital account will not be large enough to absorb the full depreciation on the project. The only way it can be allocated 99% of the depreciation is by agreeing to make an additional investment, when the partnership liquidates, if the investor still has a negative capital account at that time. This is called a deficit restoration obligation or DRO. Tax equity partnerships do not liquidate in the ordinary course.

DROs have hit as high as 70% of the original investment in some deals recently.

The only way a tax equity investor will agree to such a high DRO is if the partnership continues to allocate the investor 99% of income from electricity sales after it reaches the flip yield. The additional income allocations increase its capital account. However, the investor will also want tax distributions to cover the taxes it will have to pay on

DROs in tax equity deals are reaching as high as 70%.

this income. This will divert cash that would otherwise have gone to the developer partner who is the borrower on the back-levered loan.

The back-levered lender should examine the model to see when and to what extent the investor's capital account will go negative and when the deficit is expected to be eliminated. The lender should require such tax distributions to be covered by a cash diversion guaranty,

Tax Change Risk

Tax equity deals negotiated during 2017 were being done at a time when no one could be sure what the US tax code would say. Congress spent most of the year talking about a massive tax bill. The bill was ultimately enacted at year end.

Fortunately, it did not change the amounts or already existing phase-out schedules for the investment tax credit or production tax credit for renewable energy projects.

However, the bill affected existing projects because it lowered the corporate tax rate.

The lower corporate tax rate has two main effects. First, a lower corporate tax rate makes depreciation less valuable. Each dollar of depreciation is now worth 21¢ per dollar of capital cost rather than 35¢ to a tax equity investor. A lender should look at the fixed tax assumptions — which is a list of tax risks that were borne by the tax equity investor — and at the instructions on computing the investor's yield. The documents will say in one of these two places whether a fixed tax rate — for example, 35% — or the rate in effect at the time is to be used for tracking yield. Many older partnerships fixed the tax rate at 35%. More recent partnerships assume the "highest marginal rate" at any given time. The choice of tax rate could affect how quickly the investor will be considered to have reached the flip yield.

Many deals that were signed in 2017 require a one-time resizing of the tax equity investor's investment in 2018 based on where the tax changes settled. In some deals, the investor is allowed to sweep cash to resize the investment if the investor invested too much based on the final corporate tax rate.

One thing developers will be interested in learning as 2018 unfolds is how tax-change risk will be handled in deals now that corporate tax reform is out of the way. Before 2017, with the exception of the corporate tax rate and sometimes how depreciation is calculated, the investor took tax-change risk about the deal structure, but otherwise tracked its yield based on actual tax results. It is too early to say whether the market will revert to past practice. ◎

of the 100 returns, only one reported a significant gain or loss despite the huge swings in bitcoin prices in the past year. People who owe taxes usually file closer to the filing deadline.

— contributed by Keith Martin in Washington

Environmental Update

The US Environmental Protection Agency sent interim guidance to its regional offices in late January to fill in details of its plan to let states lead on enforcement of federal environmental laws. The state must have an enforcement program authorized by EPA.

This action is part of EPA Administrator Scott Pruitt's pledge to move to "cooperative federalism."

The guidance is in the form of a memorandum sent by Susan Bodine, assistant administrator of the Office of Enforcement & Compliance Assurance, to regional EPA assistant administrators.

Bodine also announced a new pilot project at a recent conference under which EPA will use "informal" enforcement, meaning notify a facility of a violation in an effort to achieve immediate compliance without waiting for litigation or other more formal action. Bodine said this may cause a drop in enforcement cases, but could speed compliance.

The guidance says EPA will defer to states in "all EPA compliance assurance activities, such as inspections and enforcement, in authorized State environmental programs."

For inspections and enforcement, "EPA will generally defer to authorized States as the primary day-to-day implementer of their authorized/delegated programs, except in specific situations. The EPA believes that exceptions to this general practice should be identified through close communication and involvement of upper management of both agencies."

One issue with pushing enforcement to the states is many states already have tight budgets and may not have the staff or money to take on additional responsibilities for environmental enforcement.

A progress report on implementation is due at the end of September 2018. Headquarters will provide the regional offices with a format for progress reports on implementation in July, and regional offices are to provide the first progress reports by September 28 this year.

Waters of the US

The US Office of Management and Budget moved swiftly to approve a proposal for a two-year delay in enforcement of a 2015 Obama-era regulation on "waters of the United States," called the WOTUS rule, that was about to go into effect. The WOTUS rule would identify which streams, wetlands and other bodies of water have automatic federal protection. The Trump EPA and Army Corps of Engineers would like to narrow the federal protections as part of a separate rulemaking. It believes the federal government should claim jurisdiction under the Clean Water Act in fewer cases.

Attorneys general from more than a dozen states, including Mississippi, Texas and Louisiana, had sued the Obama administration to stop the WOTUS rule, saying it would apply to lands far from what has been traditionally been considered "navigable waters." Areas that are considered "waters of the United States," such as streams and wetlands, require permits to disturb and are subject to oil spill prevention and state water-quality certifications.

The 2015 WOTUS rule has been in abeyance for some time after a US appeals court enjoined enforcement. However, on January 25, the US Supreme Court unanimously set aside the injunction on grounds that the case should have been heard first in a federal district court rather than at the appeals level. The Supreme Court decision in *National Association of Manufacturers v. Department of Defense* started the clock ticking on lifting the injunction in mid-February.

The Office of Management and Budget then moved quickly to approve a proposed EPA rule delaying enforcement that was already in the works. The delay became official on January 31.

Lawsuits

States and environmental groups that support the 2015 WOTUS rule vowed to overturn the delay in court.

Attorneys general from 10 states and the District of Columbia sued the Trump administration on February 6. The states filing suit are New York, California, Connecticut, Maryland, Massachusetts, New Jersey, Oregon, Rhode Island, Vermont and Washington.

One issue in the litigation is what happens during the period that enforcement of the 2015 WOTUS rule is delayed.

One critic of the delay, the Southern Environmental Law Center, says it will leave EPA and the Army Corps "to apply the text of the Clean Water Act directly, making thousands of case-by-case determinations with no regulatory structure to guide them and ensure consistency."

Almost all environmental proposals land inevitably in court. It does not matter whether they move in the direction of stronger enforcement or roll back existing rules. In this case, the challengers are expected to argue the Trump administration violated the Administrative Procedures Act because the agencies pushed the rule into effect without a proper rationale to support the delay and without providing a meaningful opportunity for public comment. The rush to act left the public with only 21 days to comment, and the almost immediate decision after the comment period suggests the comments were not given any real consideration.

The agencies received more than 4,600 comments.

There is also controversy around whether the two-year delay in enforcement amounts effectively to repeal of the 2015 WOTUS rule without following the procedures required to rescind a major environmental regulation.

Enforcement of an Obama regulation to extend federal protection to more bodies of water will be delayed two more years.

Industry groups and states that oppose the 2015 WOTUS rule are scrambling separately to ask federal district courts for preliminary injunctions to halt enforcement of the 2015 WOTUS rule in case the two-year delay announced by EPA is struck down in court.

Fallout

Litigants have begun to use the Supreme Court ruling that district courts are the proper venue for certain challenges under the Clean Water Act as a tool in other pending lawsuits on environmental issues.

One example is in an ongoing dispute over an EPA decision in September to delay enforcement of Obama-era standards requiring power plants to install equipment to remove heavy metals from wastewater discharges. The litigants were already fighting over whether the suit should be heard in a district court or appeals court. EPA announced a two-year delay in certain deadlines in September, a decision that is also being challenged.

Clean Air

There are rumors that EPA Administrator Scott Pruitt may move next to ease enforcement of pollution limits under the national ambient air quality standards program.

The program limits permitted levels of air pollution and has been the main tool the US government has used to improve air quality over the last 50 years. It is largely responsible for transforming US skies from the near China-like conditions experienced in some parts of the US in the 1960s and 1970s to the comparatively pristine levels of soot, haze and other observable pollutants we have today, along with addressing certain non-observable hazards such as lead.

The Clean Air Act requires EPA to set national ambient air quality standards for allowable concentrations of six pollutants in the outdoor air. The six are particle matter, ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide and lead. They are called "criteria" air pollutants because certain levels of each may be reasonably anticipated to endanger public health or welfare. The statute requires EPA to establish a level safe for human health for each with an adequate margin of safety, without regard to cost.

Each area of the country is designated as in attainment, not in attainment, or unclassifiable for each criteria pollutant. The designations change over time as pollution levels fluctuate. A particular power plant may be located in an area that is in attainment for one criteria pollutant, but nonattainment for another criteria pollutant, which could result in more stringent permit requirements.

Once the federal standards are set, states determine their own paths to reduce emissions, which gives states the ability to target reductions with the greatest cost-benefit ratio or to target the lowest hanging regulatory fruit within their borders.

To meet ambient air quality standards, state air agencies develop what are called state implementation plans, or SIPs, that describe how air quality will be maintained if in attainment and how it will be brought into compliance if not. The SIP process produces legally enforceable */ continued page 56*

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emissions limits and control requirements and, as such, is an important regulatory tool for controlling air emissions from stationary sources such as power plants.

The national ambient air quality standards are not set in stone. The Clean Air Act requires EPA to review them in light of developing science every five years to determine whether they should be adjusted.

Some states and industry have called for modernization of the review process.

When EPA fails to review the standards on schedule, the agency is often sued to force it to act.

Many on all sides recognize that the five-year time frame has proved too short to allow EPA to review and revise the standards, and then for any new standards to filter down to the states for implementation in their plans.

Critics of the current agency head are suspicious that some delays are a conscious decision not to enforce US environmental laws.

For example, EPA was sued last year for failing to meet a statutory deadline for designating areas of the country that did not meet a 2015 ozone standard, a standard that Pruitt sued EPA to block while he was the Oklahoma attorney general.

When he originally proposed to delay the designations — an action EPA has since withdrawn but without making any designations anyway — Pruitt said the delay was needed to "consider completely all designation recommendations provided by state governors," and to "rely fully on the most recent air quality data." Pruitt also wrote that the "additional time will also provide the Agency time to complete its review of the 2015 [national ambient air quality standards for] ozone."

In response, critics suggest that EPA spends time trying to delay implementation of the national ambient air quality standards just to turn around to argue that EPA should not update those standards because the states have not implemented the previous standards that the agency itself delayed.

More litigation is sure to follow.

— contributed by Andrew E. Skroback in Washington

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