

PROJECT FINANCE

NewsWire

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The Market Reacts to Possible US Tax Reforms

by Keith Martin, in Washington

The possibility that Congress will overhaul the US tax code is already having a number of effects on the market.

Corporate tax reform is unlikely to start moving through Congress before the spring. It is unlikely to reach the President's desk before December 1 at the earliest.

The House tax committee staff has been working to convert a 35-page blueprint released last June into bill language. The House plan would make five major changes of consequence to the project finance community. It would reduce the corporate income tax rate to 20%, allow the full cost of assets purchased to be deducted immediately, deny interest deductions, exempt export earnings from income taxes, and deny any cost recovery on imported goods and services.

The most controversial part of the House plan is the "border adjustment" or treatment of imports and exports. Economists say that the dollar would strengthen enough to offset the additional tax burden on importers. US retailers and oil refiners have lined up against the plan. President Trump "does not love it." He has seemed more interested in import tariffs. The border adjustment would raise roughly \$1.2 trillion in additional taxes. Without it, the plan is too costly.

The Senate tax committee chairman, Orrin Hatch (R-Utah), suggested in a speech to the US Chamber of Commerce in early February that the Senate will write / continued page 2

IN THIS ISSUE

- 1 The Market Reacts to Possible US Tax Reforms
- 4 Cost of Capital: 2017 Outlook
- 16 Saudi Renewables: Reset and Relaunch
- 21 Negotiating Corporate PPAs in the Middle East and Africa
- 30 Growth Area: Regasification and LNG-to-Power Projects
- 34 Trump and Africa
- 36 Off the Grid in Africa
- 40 2017 Market Trends
- 49 The Art of the Deal: An Alternative View
- 50 Solar Tax Equity Update
- 54 Environmental Update

IN OTHER NEWS

A TRUMP EXECUTIVE ORDER for federal agencies to withdraw at least two existing regulations for each new one proposed could delay future tax guidance.

All new policy guidance remains on hold in the meantime until the new Trump team has time to settle into office. That includes a notice that US solar companies hoped to see late last year that will explain when solar projects will be considered under construction in time to qualify for a 30% investment tax credit. The credits start phasing out after 2019. The freeze on guidance is expected to affect all forms of published IRS guidance, but not private letter rulings. / continued page 3

Tax Reforms

continued from page 1

its own tax bill. Hatch said “at least half the Senators” have reservations about the border adjustment. Four economists that are the godfathers of the plan released a 98-page paper through Oxford University in late January explaining how the tax would work.

Progress has stalled while Congressional Republicans await a Trump plan that the President has promised to release in late February.

Consequences

The House plan would have a number of effects.

The tax rate reduction would mean less tax equity will be raised on renewable energy projects in the future. Tax equity accounts for roughly 50% to 60% of the capital stack for the typical wind farm and 40% to 50% for the typical solar project. Any reduction in the percentage of tax equity will have to be made up with more debt or equity.

Lower tax rates would also ultimately reduce the supply of tax equity, although how much is unclear. Three banks account for roughly 40% of the US tax equity market. It is unclear to what extent they will be constrained by tax capacity, even at lower rates, or whether any limit on the amount they invest is tied more to the need for risk diversification. Tax equity yields are a function of demand and supply. A dip in supply while demand remains constant could lead to slight upward pressure on yields.

Debt would be more expensive. Some companies are moving to sign up corporate or construction revolvers so that interest remains deductible. Transition rules should normally shield companies from a loss of interest deductions on outstanding debt.

Companies rushed to sign binding contracts before Congress voted on the last corporate tax overhaul in 1986.

However, a substantial modification of the terms of an existing debt would lead to loss of interest deductions, since the company would be considered to have entered into a new loan.

Many wind companies signed “PTC components” contracts in 2016 in order to qualify for production tax credits at the full rate on wind farms they will build over the next four years. Follow-on agreements are being negotiated for the rest of the turbines. Developers may pressure vendors to supply turbines from US factories.

The vendor may be the one exposed in cases where final assembly occurs in the United States from imported parts. Backers of the border adjustment argue that it is equivalent to a value-added tax, but with the ability to deduct wages. If true, then a turbine vendor assembling equipment in the United States from imported parts could find itself paying US income taxes on close to its gross receipts because of inability to treat the imported parts as a cost of goods sold. Whether it works this way in fact will depend on how the House tax committee staff decides to implement the border adjustment. There is more than one way to do it.

Binding Contract?

The last time Congress overhauled the US tax code in 1986, project developers rushed to sign binding contracts to lock in tax benefits ahead of the first vote in the House tax committee. The US constitution requires tax bills to originate in the House. Congress does not usually hold out a carrot to induce companies to invest and then withdraw it after they have already committed to investments. The 1986 Tax Reform Act repealed the investment tax credit and slowed depreciation allowances, but it had numerous transition rules that let companies that signed binding construction contracts or power purchase agreements that com-

mitted them to projects complete the projects, within time limits, and still claim the tax benefits on which they were counting when signing such contracts.

It is a tougher call this time for developers whether to lock into contracts. There is no protection from tax rate changes. “Anti-churning” rules can be expected

to prevent anyone who locked into an investment from claiming any faster depreciation that is allowed under the newly revamped tax code.

There is the potential for a freeze in some types of investment to await better cost recovery.

Some tax equity investors are already pricing based on a 25% tax rate. For existing partnership flip transactions, the lower tax rate could delay or accelerate the flip, depending on when during the life of the deal it takes effect. The earlier in the deal, the more likely it will lead to delay. Delay means the developer will end up having to use cash on which the developer was counting to get the tax equity investor to the flip yield.

The later in the deal the tax rate change takes effect, the more likely it is to accelerate the flip. Partnership flip documents routinely bar a flip in sooner than five years to comply with Internal Revenue Service guidelines. An acceleration in the flip could complicate wind deals since the flip may occur before the production tax credits have run.

Flip deals signed this year may end up with additional pay-go payments by tax equity investors that are a function of the remaining tax credits, especially for deals that price by assuming a 25% tax rate in event that the rate reductions are delayed or are ultimately not as steep. IRS guidelines limit the permitted pay-go payments to no more than 25% of the total tax equity investment.

Most sponsors already bear the risk that tax rates or depreciation calculations will change in partnership flip transactions in which the tax equity flips after reaching a target yield. In time-based flips where the tax equity investor flips on a pre-set date, the tax equity investor takes tax-change risk. At least one investor in such transactions is now asking sponsors for an indemnity to make up any loss in value of tax losses.

Tax equity investors will want to take the 50% depreciation bonus this year to accelerate deductions against the current 35% tax rate. They should have an interest in closing deals this year ahead of any tax rate deduction.

There could be a pause in the market at some point during the year once statutory language is released while the market digests the contents.

However, if, as many tax lobbyists predict, any tax rate reduction does not take effect before 2018 and is phased in over time to manage the cost, the market could have an incentive to close as many deals as possible this year against the higher tax rate.

/ continued page 4

IN OTHER NEWS

The executive order requiring at least two regulations to be withdrawn for each new one proposed defines “regulation” broadly to mean any “agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or to describe the procedure or practice requirements of the agency.”

The order is Executive Order 13771. It was issued on January 30.

A set of questions and answers about the order issued by the Office of Management and Budget on February 3 limited the focus during the remainder of fiscal year 2017 to “significant regulatory actions.” The government fiscal year runs through September 30.

Significant regulations are ones that have at least a \$100 million effect on the economy or a material adverse effect on any sector or jobs, create a serious inconsistency with an action taken by another agency, materially alter the budgetary effect of grants, loan programs, entitlements or user fees, or “raise novel legal or policy issues.”

Such regulations are already subject to lengthy review by OMB. Fewer than 200 proposed regulations a year fall into this category.

OMB said the order does not apply to independent agencies, like the Federal Energy Regulatory Commission, but it encouraged them to try to offset the costs of new regulatory actions.

The order directs the federal government for the remainder of fiscal 2017 to keep the net incremental cost of all new regulations finalized this year at or below zero. The calculations will take into account any existing regulations that are withdrawn.

Costs are measured as the lost opportunity cost to society.

Starting in fiscal 2018, new regulations cannot be issued unless they are included in a “unified regulatory agenda” kept by OMB or special approval is given by the OMB director. All agencies will have to work to get planned regulations on the master list.

/ continued page 5

Tax Reforms

continued from page 3

Other Structuring Challenges

Full expensing of capital costs will complicate deals after this year. Tax equity investors pay only a fraction of the full project cost for an interest in a project partnership. Each partner has a capital account that limits the amount of depreciation it can claim. Investors will run out of capital account in the first year causing the remaining depreciation to shift to the sponsor. The shift could also drag tax credits with it, making the financings less efficient.

Falling electricity prices combined with the tax rate reduction may bring back project-level debt. It has been rare to find debt at the project level in transactions in the last few years. Tax equity investors have pushed lenders behind them in the capital structure. Most debt today is back-levered debt at the sponsor level. The lender looks to the sponsor share of cash flows to pay debt service. Lower electricity prices are pushing deficit restoration obligations in flip deals to the 40+% range, meaning that investors are running out of capital account before they are able to absorb the full depreciation they want. The main way investors deal with this problem is to agree to invest more when the partnership liquidates in order to cover any negative capital account. This allows them to continue taking tax losses despite having a negative capital account. The 40+% is a promise to invest up to another 40+% of the original investment. Investors are reluctant to agree to DROs that are much higher. Adding debt at the project level is another way to allow the investor to absorb more depreciation.

In deals with multiple fundings, the parties are negotiating how far into the legislative process a proposed adverse tax law change must have moved before it becomes a reason to suspend further fundings. Most transaction documents make it a condition to further fundings that there not have been a materially adverse “proposed change in tax law.”

Meanwhile, developers are wrestling with what cost of capital to assume when bidding for power purchase agreements. It may be hard to get utilities to adjust the electricity price to hold the project harmless from a change in tax law.

Schmuck Insurance

In acquisitions — M&A deals — some buyers are asking for “schmuck insurance.” They want a one-time price reset after the tax overhaul bill is enacted. No one wants to feel like a schmuck for having overpaid.

Operating projects should be more valuable because the projected after-tax cash flows will be higher. This could help yield cos. Any appreciation in the dollar caused by the border adjustment will make US assets more valuable while at the same time reducing the value of US companies’ holdings overseas.

Some lenders making tax equity bridge loans in solar deals are demanding a sponsor guarantee in view of the uncertainty. Back-levered lenders are concerned about the potential lengthening of tax equity tenors as more cash shifts to tax equity investors to make up for loss in time value of depreciation due to a tax rate change. However, the shorter the tenor of the back-levered debt, the less likely this will be an issue. ☺

Cost of Capital: 2017 Outlook

The Trump presidency and the likelihood of corporate tax reform have added an element of unpredictability to the year ahead. More than 2,000 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 for North America for Investec, Tim Chin, managing director and head of power, infrastructure and project finance in North America for BNP Paribas, Jean-Pierre Boudrias, managing director and head of project finance at Goldman Sachs, and John C.S. Anderson, head of North American corporate finance at John Hancock/Manulife. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: John Eber, what was the tax equity volume in 2016? How did it break down between wind and solar?

Tax Equity

MR. EBER: We are still finalizing our data on the commitments that were issued in 2016, but based on our current analysis, we see a market that was about \$11 billion of new tax equity commitments in 2016. This breaks down to a little over \$6 billion in wind and the rest in solar.

This is down from last year’s market that was almost

\$15 billion in tax equity. The big difference seems to be in the utility-scale solar side, which saw a significant uptick in 2015, but was down to a much smaller number in 2016.

MR. MARTIN: Why the drop off in utility-scale solar? This is a significant drop of almost \$4 billion in tax equity.

MR. EBER: The interesting thing is the market is about the same size as it was in 2014, so we had a big increase in 2015 of over 40% due predominantly to the utility-scale solar market. The expected expiration of the investment tax credit led to a lot more commitments being sought in 2015. The market in 2016 fell back to its previous level, which was still sizable in historic terms. In 2013, the market was \$6.5 billion in total between wind and solar.

MR. MARTIN: So when the tax credits were extended by Congress at the end of 2015, the market was fairly exhausted. People stopped to catch their breath; 2016 got off to a slow start. The pipeline of utility-scale solar projects had thinned and now has to be rebuilt.

MR. EBER: I guess you could say that. Many people thought that might happen. I think you yourself asked me if I thought that was going to happen, and we didn't know for sure, but the numbers suggest that it did.

MR. MARTIN: Jack Cargas, journalists were asking at year end whether the tax equity market has frozen in anticipation of corporate tax reform. Has it?

MR. CARGAS: It has not. The market continued to function normally after the November election. The market was still robust in 2016 and that continued through the end of the year. Transactions that closed or funded post-election had different structures in some cases, and they ran the gamut from deals that did not change at all from their pre-election assumptions all the way across the spectrum to deals that included rights to restructure completely in the event of a change in tax law or proposed change in tax law. It seemed that most investors found a way to deliver for their clients before year end.

MR. MARTIN: What do you expect this year? We could be in the midst of a tax reform debate for a good part of the year. Do you think the market will continue functioning normally throughout that debate?

MR. CARGAS: We certainly are in the midst of tax reform debate, but we are in a different place than we were a month ago. There is no immediate pressure to fund now that we are past year end. We and many other market participants are taking a hard look at various regulatory scenarios and what kind of impact they might have on structures. / continued page 6

OMB is also supposed to come up each year with an internal regulatory budget at the same time it draws up the federal budget to present to Congress. It will allocate the total incremental cost of new regulations that can be issued during the year among the various federal agencies.

It has been longstanding practice to treat most tax regulations as interpretive and therefore exempted from review as significant regulations. It is not clear whether this policy will continue.

Many tax regulations fill in important detail in tax statutes for businesses that need certainty about how new tax laws enacted by Congress work before moving forward with transactions. Many tax regulations are also so highly technical that it would be hard for OMB to do a meaningful review. The Treasury has treated only two sets of regulations as significant since 2011.

Meanwhile, the Senate tax committee chairman, Orrin Hatch (R-Utah), said in a letter to the Obama Treasury secretary, Jacob Lew, in October that he would work to subject more tax regulations to cost-benefit review. The Government Accountability Office, an arm of Congress, recommended in a September 2016 report that there be a reevaluation of existing policy of exempting most tax regulations from such analysis.

Canada adopted a one-for-one regulation policy in April 2015 that requires the federal government to remove at least one regulation for every new one introduced. The Red Tape Reduction Act passed parliament 245 to 1. It builds on a program of reducing red tape that has been in effect in British Columbia since 2001 and that has led to a 43% reduction in regulatory requirements compared to when the initiative started.

FEWER CORPORATE PPAS were signed in 2016 than expected at the start of the year.

Projections were that 4,000 megawatts of power purchase agreements would be signed directly with corporate purchasers of electricity. The final number was 2,194 megawatts,

/ continued page 7

Cost of Capital

continued from page 5

I think the market is generally of the view that there are two areas of potential change that would affect deals. The first is the tax credit regime. Tax reform could lead to a reduction in or even elimination of the investment tax credit and production tax credits. However, I think most market players believe that such changes are unlikely.

The second change is a likely reduction in corporate tax rates, including those suggested by the president elect during the campaign and in the House Republican blueprint. Obviously various proposals have been floated, including reduction of the marginal corporate tax rate from 35% to 20% or even 15%, and assumptions about the magnitude and timing of any such reduction can have significantly different impacts on transaction economics.

So we expect lots more analysis, and we expect structural changes. The structural changes could include things like the election of bonus depreciation and possibly lower investment amounts per transaction, but as we see on a daily basis in the press, expectations about what might happen keep shifting.

MR. MARTIN: John Eber, what do you expect this year during the tax reform debate?

MR. EBER: I think Jack covered it pretty well. People are trying to analyze all the possible permutations. There is the potential for the tax rate, the ITC, PTCs and depreciation to change. We agree with Jack that it seems most of the attention is focused on tax rates.

Even there, you have a lot of permutations as to which rate and, even more importantly, when that rate might be effective. If the new rate will not take effect until a future year, then I think the debate in Congress will have a limited effect on the market in 2017. If anything, people might want to accelerate deals to claim tax losses against a higher tax rate.

MR. MARTIN: Both of you suggest tax equity investors are more likely to elect bonus depreciation. They had not been willing to price it into deals very frequently in the past.

MR. EBER: That's correct. Let's step back. The risk of tax rate change has been borne by the developers for years, because there is both a potential benefit and a potential detriment from rate changes, depending on when they occur during the term of the deal. If you do not make any structural changes, the flip would move out as the tax rate is reduced. Electing bonus depreciation is one way to mitigate some of the effects of a potential tax rate change.

MR. MARTIN: Will the lower corporate tax rate reduce the potential supply of tax equity, or is tax capacity unlikely to be a constraint since most of the tax equity investors are banks and insurance companies with potentially unlimited tax capacity, even at lower rates?

MR. CARGAS: It is a little too early to tell, but it is possible that the availability of tax equity could be reduced going forward. A few investors could exit the market due simply to the massive uncertainty or to the expectation that corporate tax rates will be reduced with the result that these investors will no longer need as much tax shelter.

MR. EBER: It is hard to tell because most people's tax positions are confidential, so these numbers are not readily available.

MR. MARTIN: Is tax capacity a constraint for big banks?

MR. EBER: Not for J.P. Morgan.

MR. MARTIN: I assume the answer is the same for Bank of America Merrill Lynch?

MR. CARGAS: I think most financial investors are going to stay in this business. Their business is to provide financing to their customers.

MR. EBER: I agree. More investors are active in the market compared to four or five years ago. New investors came in last year. There are investors who wanted to invest last year who were unable to find deals, so I think that the market on the tax equity side is as healthy as it has been for a while.

But again, there are a lot of different tax rates being bantered around and no transition rules have been announced so, as Jack said, it is difficult to know the potential effect on the market.

MR. MARTIN: The cost of tax equity is a function of demand and supply. I think we heard that supply is not likely to increase. It could decrease somewhat. How do you see the demand curve moving, and ultimately the question is in which direction do you sense yields are moving?

MR. EBER: I think the demand side has been stable. We saw a big spike up in 2015, but 2016 brought us back to a more normal level of demand. The wind side on tax equity has been stable, in the \$6 to \$7 billion range for the last three years in a row, and I think the solar side has the potential to stabilize as well. We see modest continued growth in demand going forward, assuming no revocation of ITCs or PTCs, and the supply of tax equity seems to be more than adequate to accommodate that growth.

MR. MARTIN: Two more questions. Jack Cargas, what percentage of the capital structure is covered by tax equity today in the typical wind or solar project?

MR. CARGAS: In wind, tax equity usually amounts to 60% of capital stack. We have seen higher and lower figures depending

on the amount of cash available for distribution to the tax equity investor, but 60% is pretty typical for us. In solar deals, it has been more like 50%.

MR. MARTIN: John Eber, do those numbers sound right to you?

MR. EBER: Yes they do.

MR. MARTIN: I could swear the two of you said during the tax equity panel we did together at the AWEA fall finance conference that tax equity amounted to 40% to 50% in a typical wind project.

MR. EBER: We do not usually see it below 50% in wind projects. Generally wind is in the 50% to 60% range. Solar is in the 40% range.

MR. MARTIN: Last question. Are there any other noteworthy trends in the tax equity market as we enter 2017?

MR. CARGAS: A trend we have seen the last few years is that transactions have become more and more complex, and we can expect that trend to continue. We have seen the inclusion of back leverage and RECs and hedges and basis risk and environmental issues and corporate PPAs and many other developments. The market will have to evolve further to accommodate new political uncertainties.

We expect investors to continue to add more tools to their toolboxes. We are confident the market will continue to exhibit the adaptability necessary to continue to finance these assets.

MR. MARTIN: John Eber, other noteworthy trends?

MR. EBER: Several sources have recently reported on their estimates of the volume of wind turbine equipment that was delivered by year end 2016, or will be delivered in early 2017, as a means to treat projects built over the next four years as eligible for full production tax credits. One source said costs were incurred in 2016 on enough equipment to treat 30,000 to 58,000 megawatts of projects as under construction in time. Another source had 40,000 to 70,000 megawatts. If you break that down on an annual basis, it is on average maybe as much as 10,000 megawatts a year of wind over the next four years that would qualify for PTCs at the full rate.

From a tax equity standpoint, that suggests there will be a healthy, active market for the next four years. That is really good for the wind business in terms of being able to compete against solar. The numbers do not include potential repowerings or projects on which construction started under the physical work test. The bottom line is that it looks like a vibrant wind market ahead for the next four years.

MR. MARTIN: What does 10,000 megawatts a year of wind translate into in terms of billions of dollars tax equity per year?

MR. EBER: The current market, in terms of tax equity translated into megawatts, is about 6,000 to 7,000 / continued page 8

according to Renewable Choice Energy, a broker that helps arrange such contracts. Some companies may have been reluctant to lock in long-term purchases because of a perception that electricity prices will fall.

Buyers during 2016 included Johnson & Johnson, 3M, Dow Chemical, Google, Microsoft, Amazon, MIT, the University of California, the University of Illinois, Ithaca College, Steelcase, Lockheed Martin, Avery Denison, Salesforce, HSBC, Digital Realty, Iron Mountain, General Motors, Target, Walmart, and the US Army.

In 2015, 3,260 megawatts of corporate PPAs were signed. There were 1,494 megawatts of corporate PPAs signed in 2014.

OKLAHOMA is considering imposing a tax on electricity generated from wind.

The governor, Mary Fallin (R), proposed such a tax of 0.5¢ per KWh in the fiscal year 2018 budget she sent the state legislature. Fiscal 2018 starts on July 1, 2017.

Oklahoma would be the third US state to impose such a tax. 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.

The Oklahoma legislature is also debating whether to end a tax credit of 0.5¢ a KWh for generating electricity from wind before its scheduled expiration date. The tax credit may be claimed for 10 years on the electricity output. It may be claimed on any new wind farm put in service by December 2020. Efforts last year to scale back the credit failed. A bill to end the tax credit for projects put in service after June 2017 cleared a House subcommittee in early February. The bill would also cap the total amount of tax credits that can be claimed by all wind generators at \$15 million a year starting in fiscal 2018.

DEVELOPERS dealing with the US military and other federal agencies got help from the IRS.

Such developers often enter / continued page 9

Cost of Capital

continued from page 7

megawatts a year and, of course, not all wind developers use tax equity. Each year, we get a few more players who come in who can own and operate and not need it. The current market would be adequate to service that type of volume.

Bank Debt

MR. MARTIN: Let's shift to bank debt. We have Ralph Cho from Investec and Tim Chin from BNP Paribas. Either of you, what was the volume of North American project finance bank debt in 2016 compared to 2015?

MR. CHO: From a dollar perspective, 2016 transactions totaled about \$35 billion compared to about \$60 billion the year before. That was about a 42% drop in dollar volume.

MR. MARTIN: Dramatic.

MR. CHIN: There were a number of huge LNG deals that came to market in 2015, but not in 2016.

MR. CHO: If you go a little more granular, by my count there were 137 deals in 2016 compared to 160 deals in 2015. In terms of number of deals, there was only a 14% drop. Another difference in deal volume is that there were fewer quasi-merchant gas-fired power projects done in 2016 compared to 2015. What was left were renewables deals, especially solar, and they tend to be smaller transactions.

MR. MARTIN: Do you expect LNG to make a comeback this year?

MR. CHO: I do not.

MR. MARTIN: How many active banks were there in 2016, and how many do you expect in 2017?

MR. CHO: During 2016, we worked with 50 to 60 project finance lenders who were actively hunting for deals. I think that this represents market capacity of about \$3 billion. For 2017, we

expect to continue to see new lenders, especially from Asia and particularly from Korea. They are attracted to the opportunities in the US market, and they are committing large dollars.

On top of that, we also see international commercial banks coming back into project finance, so it is a safe bet to say that there will be an uptick in liquidity in 2017. This is good for borrowers. It will make for more competition among lenders for deals.

MR. CHIN: Probably only four or five banks on the list of active banks are leading transactions. With respect to Korean banks, most of that liquidity is being sourced by brokers and advisors. As Korean banks become more familiar with the US project finance market, we will probably see them lending directly or at least through the syndications teams of the global project finance banks.

MR. MARTIN: Ralph Cho, going back to you, we have been hearing for the last two years that the market is awash in liquidity, and you are saying there is more liquidity still coming.

MR. CHO: Correct.

MR. MARTIN: What is a good adjective to describe the next stage of liquidity beyond "awash"?

MR. CHO: More awash? Abundant?

MR. MARTIN: What is the current spread above LIBOR for bank debt, and what is it as a coupon rate?

MR. CHIN: The spread on the transaction varies based on the type of financing. For a fully contracted project and plain-vanilla nonrecourse financing for a good sponsor, I would quote a range somewhere around 162.5 to 200 basis points as a margin above LIBOR. If you look at other sectors like quasi-merchant gas-fired power plants, they will obviously carry a higher spread: probably 325 to 350 basis points.

To calculate the coupon from a borrower's perspective, add LIBOR. The three-month LIBOR rate today is approximately 1%. So add 1% to your spread and that is generally what lenders are

receiving in the market. However, keep in mind that banks require borrowers to hedge the majority of their floating-rate exposure. Call it a 5-year average-life swap spread. We are quoting somewhere in the 2% to 2.25% range, so you would add that on top of your margin to calculate a coupon that the borrower would have to pay.

MR. MARTIN: Is the upfront fee equal to the LIBOR spread?

Tax equity deal volume was down in 2016 from the year before.

MR. CHIN: We are seeing the LIBOR spread a little bit wider than the upfront fee.

MR. CHO: It is more of a coincidence if you see the LIBOR spread and the upfront fee at the same level. Upfront fees reflect compensation for the work that lenders have to do and their balance sheet usage. LIBOR spread is more reflective of the bank's cost of capital plus the return.

Borrowers should expect to pay an arranger fee and some original issue discount as the two elements of the upfront fee.

The arranger fee ranges between 50 and 100 basis points and is split among the book runners. If a lender is really desperate to be one of the lead banks, it may agree to a fixed fee. That could be less than this amount. It happens occasionally.

The original issue discount is a fee paid to the lenders that are committing to the transaction. The book runners like to offer an OID level that is tied to the amount each lender is willing to commit. For example, for retail-level tickets of \$25 million or less, we offer lenders OID somewhere between 100 and 150 basis points, and the highest chair lenders who are committing \$75 to \$100 million or more are receiving somewhere in the neighborhood of 200 to 250 basis points.

If the borrower wants a firm underwriting commitment, an additional fee would be charged that is generally around 50 to 100 basis points.

MR. MARTIN: Some companies in the wider market are moving to borrow ahead of any move by Congress to deny interest deductions, figuring that existing debt will be grandfathered. Have you seen any greater interest in corporate or construction revolvers as a consequence of this?

MR CHIN: That is an interesting question. We have not seen that trend yet in the project finance market.

MR. MARTIN: Is it still the case that there is no LIBOR floor in the bank market?

MR CHIN: Correct.

MR. MARTIN: What are current loan tenors?

MR CHIN: The quasi-merchant stuff is usually done with a mini-perm structure over construction plus five or seven years. If the project has a long-term power purchase agreement, we could structure the debt amortization over the life of the PPA, but retain the shorter tenor so the borrower gets the benefit of the longer amortization schedule.

MR. CHO: I agree with that. Most of the market is around that five- to seven-year sweet spot. In some fully-contracted deals, you might have heard about longer tenors like construction plus

/ continued page 10

into energy savings performance contracts under which they agree to install solar systems or other energy efficiency improvements in exchange for a share of the savings the government realizes on its electricity bills.

Federal law allows US agencies to enter into energy savings performance contracts with terms of up to 25 years. An Office of Management and Budget memorandum requires title to the improvements to transfer to the government at the end of the contract.

This makes it hard for developers to claim tax benefits on the improvements. Tax credits and depreciation may only be claimed by the tax owner. US tax rules normally treat a customer who will become the owner of equipment when the contract ends as the owner from inception.

The IRS issued a "safe harbor," or set of guidelines, in late January, at the urging of the solar industry, for energy savings performance contracts with federal agencies that, if followed, will insulate such contracts from challenge by the IRS.

The guidelines are in Revenue Procedure 2017-19.

To fit in the guidelines, the contact cannot have a term longer than 20 years. A developer who has already signed a longer-term contract for a project that is not yet in service should try to amend it to shorten the contract term.

The federal agency cannot operate the equipment.

The agency should not be required to pay for services it does not receive, except during temporary shutdowns for maintenance or for making repairs or capital improvements.

The agency should not share in the developer's profits. Thus, for example, the contract price should not be adjusted to pass through savings in operating costs.

The agency can have an option to purchase the project, or even be required to purchase it, as long as the price is fair market value determined at time of purchase. Fair market value means a price the parties negotiate */ continued page 11*

Cost of Capital

continued from page 9

10 years all the way up to construction plus 18 years. Within the 50- to 60-bank universe that I mentioned earlier, I would say about a third of those banks would be willing to commit on a longer-term basis.

If I had to guess, I would say that the market capacity for long tenors all the way up to construction plus 18-year money would be in the \$500 to \$700 million range.

MR. MARTIN: Out of \$3 billion.

MR. CHO: Correct.

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

MR. CHO: They are all different. For wind, they are somewhere in the range of 1.4x to 1.45x debt service. For solar, you probably can size it a little bit tighter given the shorter standard deviation in your forecast for irradiation, so call it 1.3x.

The bank market is expected to remain awash in liquidity. LIBOR spreads have narrowed.

We have been doing residential solar deals, and we have been sizing those at 1.5x just because of the nature of the customer agreements. For contracted plain-vanilla gas plants, you are probably looking at 1.4x to 1.45x.

MR. CHIN: On the quasi-merchant side, we are seeing base case coverage ratios of a minimum of 2.0x to 2.5x, and an average of 2.5x to 3x, but the way we size the debt reduces the coverage ratio to a range of 1.25x to 1.3x.

MR. MARTIN: What does that mean?

MR. CHIN: Take a merchant gas-fired power plant with a hedge and capacity payments in PJM. We are not taking any merchant energy into consideration when we size the debt. We look only at the hedge and capacity payments. The coverage ratio looking just at those payments is 1.25x to 1.3x.

MR. MARTIN: What are advance rates currently on construction debt?

MR. CHO: Advance rates are generally based on what cash flows you expect after the plant starts operating. If it is a fully contracted plain-vanilla asset with healthy cash flow, the borrower should be able to leverage up to 80% to 85% on a senior basis.

When you start looking at deals like quasi-merchant deals where the cash flow is not fully locked in, then the leverage falls significantly. We are in the market today with one where the advance rate is slightly below 50%. The developer will have to put up a significant amount of cash equity.

MR. MARTIN: Are you describing advance rates for term debt or construction debt?

MR. CHO: We do construction plus term. We would start lending you money from day one when you first break ground.

MR. MARTIN: You would expect the equity to fund during construction on a *pari passu* basis, and the entire construction debt would roll into term?

MR. CHO: We have seen the equity fund in two ways. The equity can fund first or the equity can fund last as long as there is a letter of credit or some other kind of credit support behind it.

MR. MARTIN: For quasi-merchant gas, at no point would you be out of pocket as a lender for more than 50% of the capital cost.

MR. CHIN: I concur with that.

MR. MARTIN: One of the big stories in the last three years has been the increase in volume of back-levered debt in the renewable energy market. It is rare to see project-level debt in that market. How do coverage ratios, tenors, and pricing change as the debt moves upstairs behind the tax equity?

MR. CHO: In 2016, approximately \$15 to 20 billion of the volume was in back leverage. At Investec alone, we probably moved \$1 billion just in residential solar, which was all back-levered debt.

To be honest, I have not seen much difference in terms of coverage ratios. Back-levered debt is still being sized against 1.3x in solar. Tenors are still five to seven years. Pricing is 175 basis points over LIBOR, give or take, based on the situation. In general,

lenders are willing to take flip risk, but they want to put in structural mitigants to protect them from the flip risk.

The tax equity structures are slowly becoming more accommodating to lenders. The tax equity investors are structuring in protection of lenders' principal and interest payments before sweeping in full for indemnity claims.

The new thing that we are starting to hear about is we see some creative structuring where tax equity investors are allowing the back-leveraged lenders to have a lien. That actually might take away back leverage. What the tax equity guys might ask for is for lenders to agree to forebear for five years and carve out preferred distributions to the tax equity investors in exchange for giving them a lien. Let's see whether or not that becomes a trend.

MR. MARTIN: Very interesting. A 12.5 basis point premium for debt that is behind the tax equity in the capital stack. That is not much of a premium.

MR. CHO: No.

MR. MARTIN: The dollar has appreciated by 4% since Trump was elected. It is up 25% over the last two years. What effect, if any, does this have on participation by foreign lenders in the US market?

MR. CHIN: I can only speak for my institution. I have not seen any effect.

MR. CHO: I agree with that.

MR. MARTIN: Are there any other noteworthy trends in the bank market as we enter 2017?

MR. CHO: The slowdown of GDP growth in Korea and the general maturation of the economy is causing Korean banks to look for higher-yielding opportunities in international markets.

Even though the US deal pipeline in general looks weak, our bank sees some potential areas of growth in 2017. We expect to see more residential solar aggregation facilities as well as aggregation takeout financings. We expect to see some consolidation of commercial and industrial solar financings through portfolios. We see utility-scale renewables activity ramping up in Mexico. Our institution is also chasing storage and infrastructure. We see these as the primary areas of growth for our business.

MR. MARTIN: Tim Chin?

MR. CHEN: Banks will probably start talking more about being overexposed to PJM. That will lead to more use of hybrid debt structures, such as including a fixed-rate debt tranche as part of a larger floating rate financing. We also see more Korean debt appetite for these transactions. We would like to see more infrastructure deals coming to market. / continued page 12

at time of purchase or, failing agreement, an appraiser determines. It is not the price at which the asset is recorded on the developer's books.

The guidelines provide an example of a transaction that works. In it, the federal agency will purchase the project at the end of the contract term for fair market value determined at time of purchase, and the developer will transfer part of the payments it receives from the federal agency during the contract term into a reserve account to credit against the future purchase price. The agency will make two periodic payments under the contract: one for electricity and the other to put in the reserve account.

The reserve account payments are set to try to equal the expected fair market value by the time of purchase. There may be periodic reappraisals and adjustments in the reserve account payments during the contract term. Any funds remaining in the reserve account after the purchase will returned to the federal agency.

The contract in the example has a schedule showing the termination values the agency will have to pay if it terminates the arrangement before the end of the contract term. The amounts vary over time.

The guidelines apply to contracts for alternative energy facilities, meaning generating equipment that does not run on oil, gas, coal or nuclear fuel. Thus, they do not apply to fuel cells.

They apply to contracts entered into on or after February 13, 2017. However, the IRS said it will not challenge contracts entered into earlier that have the required contract terms.

A POWER COMPANY was able to deduct part of the cost of a new power plant immediately on grounds that the spending was on research and development.

The IRS analyzed the case in an internal memo written to an IRS agent in the field. The memo is Field Service Advice 2017051F.

The utility had built a smaller prototype of the power plant earlier / continued page 13

Cost of Capital

continued from page 11

Term Loan B

MR. MARTIN: Jean-Pierre Boudrias, let's talk about the term loan B market. For our listeners who don't know what a term loan B is, it is basically debt papered as bank debt, but sold to the institutional market. That means that there are fewer occasions when one needs to come back to the lenders for approvals.

What was the term loan B volume in the North American power sector in 2016, and how did that volume compare to 2015?

MR. BOUDRIAS: Last year, we saw \$11.6 billion of volume across 11 transactions. That was a significant increase from the year before when we saw about the same number of transactions, just one less at 10, but the B loan volume in 2015 was only \$3.3 billion, so there was a significant increase in B loan volume in 2016.

MR. MARTIN: It sounds like the market did bigger deals. What types of deals accounted for the increase in dollar volume?

MR. BOUDRIAS: It is important to remember where the term loan B market has traditionally been active. It has been used to support new M&A activity. We saw larger such transactions tap the market last year. There were also more refinancings than we saw the year before. Those refinancing volumes are generally easier to place when one thinks that the lenders already have exposure to them.

MR. MARTIN: What percentage of the 2016 deals — you said there were 11 — were merchant gas-fired power projects?

MR. BOUDRIAS: I would not limit it to gas projects. Merchant projects were probably 50% of the mix, and the balance was a mix of small contracted portfolios and larger retail-oriented companies.

MR. MARTIN: You heard Tim Chin say just a moment ago that one trend in the bank market may be a sense of growing overexposure to PJM for merchant gas deals. Do you sense that as well in the term loan B market?

MR. BOUDRIAS: I would describe the trend in the term loan B market as follows. We had a group of investors who are in almost all the transactions in 2012, 2013, 2014 and, to a lesser extent, 2016. When you look at the performance of a lot of these financings — a large component was merchant, and obviously you overlay what happens to natural gas during the same time period — you can see a fair amount of underperformance. As a result, in 2016, some of these investors decided to stay on the sidelines. They were the people who were probably overexposed to the

sector broadly. We saw a group of new investors enter the market in 2016 for power transactions.

MR. MARTIN: Very interesting trend. The dollar volumes in the B loan market were \$11 billion in 2013, \$9 billion in 2014, \$3.3 billion in 2015, and we bounced back up to \$11.6 billion in 2016. What do you expect for the term loan B market in 2017?

MR. BOUDRIAS: My suspicion is it will be largely driven by M&A volumes. Some transactions are already known. LS Power is purchasing certain assets from TransCanada that obviously will be part of that volume. It is probably reasonable to expect that we will see a lower dollar volume than in 2016, but larger than what we saw in 2015, so probably in the \$5 to \$6 billion range. If we see a few large acquisitions, the dollar volume could increase above this range.

MR. MARTIN: Pricing for B loans tends to be higher than for bank debt. Pricing a year ago for strong BB credits was around 425 to 450 basis points over LIBOR, and B credits were 575 to 600 basis points over. Where do you see rates today?

MR. BOUDRIAS: For a BB name, probably around 350. That could even move lower when the markets open in 2017. For B credits, we are probably around 425 to 450 basis points over.

MR. MARTIN: We are in a market where people expect interest rates generally to increase and yet the term loan B rates are going down. Why?

MR. BOUDRIAS: It is important to remember those were all spreads. Unlike the bank market, there were LIBOR floors in 2016 in most deals of 1%. My suspicion is we will probably see LIBOR floors start to disappear in 2017.

MR. MARTIN: Because of competition or because the underlying rates are rising?

MR. BOUDRIAS: Investors were demanding LIBOR floors because, unlike banks, they do not fund in the floating-rate market. The larger investors in the term loan B market are what we call CLOs that are essentially structured vehicles who purchase loans. The structure of their funding tends to be fixed, so they have limited ability to deal with extremely low underlying rates. They tend to require that LIBOR have a floor so that they can service their own liabilities.

As LIBOR moves higher, we expect the floor to disappear given the expectations that LIBOR will continue to increase.

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

MR. BOUDRIAS: That's right.

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

MR. BOUDRIAS: It is really driven by repayment.

The expectation has to be that a little more than half the debt principal will be repaid by the maturity date for the loan in the downside case. For acquisition financing, investors generally want minimum equity of between 30% and 40% depending on the profile of the asset.

MR. MARTIN: What upfront fees are required? We heard about the fees required by banks.

MR. BOUDRIAS: Similar to banks, there is a component that goes to investors. Generally it is around 100 basis points. The amount fluctuates depending on market conditions. Then there is compensation for the underwriters. The amount fluctuates depending on the nature of the underwriting.

MR. MARTIN: Are the total upfront fees something like 100 basis points, 150, 200?

MR. BOUDRIAS: It depends, but probably between 100 and 150 basis points for best efforts, and about 100 basis points on top of that for underwritten transactions.

MR. MARTIN: Final question. How large a transaction must one have to make it worth the trouble to go to the B loan market, and how long should one assume the transaction will take compared to a bank loan? What is your sense of how long it takes to close a bank loan versus a B loan?

MR. BOUDRIAS: For a new transaction or new borrower, \$250 million is probably the minimum amount borrowed that is efficient for both the market and the borrower. For a new borrower, it is probably a 12-week process, most of which involves getting a rating from the rating agencies. Once a deal goes to market, investors won't really see the deal until two weeks before commitments. Closing occurs relatively quickly thereafter.

For an existing issuer, the process is probably compressed down to a week or week and a half. In a weaker market, rating agencies will work faster, and there is an ability to get additional dollars relatively quickly for companies that have already had transactions rated. In such cases, a borrowing of \$100 million or more would be economic to do.

Project Bonds

MR. MARTIN: Let's move to project bonds. John Anderson, the project bond market does not do well when the bank and term loan B markets are wide open and looking for product. You heard the bank market is awash in liquidity, and the term loan B market was pretty healthy last year but is expected to drop somewhat this year.

How many deals were there in 2016, and what are you expecting in 2017?

/ continued page 14

and was finally building one to scale. The power plant has three main systems. It uses largely proven and commercially available equipment. However, one of the systems contains equipment that is first of a kind.

The IRS said that amounts spent on design and installation of the first-of-a-kind equipment would be treated as research spending. This allows the utility to deduct the costs immediately rather than have to spread them over time as depreciation on the power plant.

IRS regulations define research for this purpose as "activities intended to discover information that would eliminate uncertainty concerning the development or improvement of a product."

The utility did not deduct the research costs initially, but filed amended tax returns later to do so. The IRS made the internal memo public in early February.

SOME TRANSMISSION AND PIPELINE companies may have to reduce the rates they charge customers.

The affected companies own interstate transmission lines and oil and gas pipelines and file tax returns as partnerships. Many pipeline companies are organized as master limited partnerships.

The Federal Energy Regulatory Commission issued a "notice of inquiry" in December about its policy of allowing interstate transmission companies and pipelines organized as partnerships to recover income taxes, even though the partnerships do not pay income taxes. FERC issued a policy statement in May 2005 permitting an income tax allowance for all regulated entities — both corporations and partnerships — provided the owners can show that taxes have to be paid on income earned by the company, even if the taxes are at the partner level.

United, Delta, Southwest, US Airways (now part of American Airlines) and several refineries sued FERC challenging a decision to let SFPP, L.P., a partnership that owns a */ continued page 15*

Cost of Capital

continued from page 13

MR. ANDERSON: I think some of the liquidity in the bank market translates to the fixed-income markets as well. We had another year of record issuance in the public bond market in high-grade debt, and the private placement market had a very high level of issuance as well.

Last year was a marginally stronger year for project bonds than 2015. In 2015, there were about half a dozen syndicated deals. In 2016, there were close to a dozen if you look across wind, solar, public-private partnerships and transportation and an LNG deal. So there was better volume in 2016, although still not a ton, but that was just the syndicated flow.

There are roughly 25 participants in the project bond market. Maybe eight to 10 of them are anchor investors. The anchor investors drive the market. They tend to be life insurance companies with larger staffs. They are also doing smaller direct deals, one-investor deals, that do not show up in the broadly syndicated numbers. The direct deals are harder to track.

Interest rates on term loan B debt are also lower than a year ago.

MR. MARTIN: When you say there were close to a dozen syndicated deals in 2016, that means in the public market and not privately placed deals, correct?

MR. ANDERSON: Correct. I am giving you numbers for syndicated deals. Generally you see project finance deals placed in the private placement market, and not in the public bond market. Sometimes you will see some in the 144A market that, again, is limited to institutional investors.

My default expectation is a flat market in 2017 compared to 2016. The 2017 numbers will depend on supply of investment capital and what needs to get financed. As rates tick up a bit,

more treasurers will say, "Base rates are still pretty low on an historical basis. Maybe it would be best to lock in the current rate before it goes higher." The project bond market is a fixed-rate market. You can lock in 20- to 25-year money at current rates, which some people may find more attractive to do in 2017 than they did last year.

MR. MARTIN: There was only one deal in the project bond pipeline last year at this time. How many do you see today?

MR. ANDERSON: We see five. That number pales by comparison with the bank market numbers that our earlier panelists were talking about. But it is a healthy flow.

MR. MARTIN: Project bonds price off treasuries. So you have a fixed rate that is a spread off treasury bonds. What is the current spread?

MR. ANDERSON: The 10-year treasury is 2.4% and the average life on a lot of project deals will be more like 12 years or a tad longer, and we see spreads of 200 to 300 basis points over. So if you look at what that turns into as a coupon, the range is probably 4.5% to 5.25%. Investors in the project bond market generally do not receive an upfront fee. They are compensated through the spread.

MR. MARTIN: The tenor is generally as long as the PPA or perhaps one year short?

MR. ANDERSON: We generally go the length of the PPA. I see that in syndicated deals frequently.

MR. MARTIN: Can project bonds be used for merchant or quasi-merchant gas projects with hedges?

MR. ANDERSON: That gets more into a BB-type credit quality. The project bond market is an investment-grade market.

MR. MARTIN: So BBB?

MR. ANDERSON: Exactly right. If you have fixed capacity payments and the other payments are merchant, lenders in the project bond market will lend solely against the capacity payments and other contracted revenue stream.

MR. MARTIN: How large a transaction does one need to do a project bond?

MR. ANDERSON: If there is only one investor, \$30 to \$50 million can make sense. If you're doing a larger syndicated deal, it probably should be at least \$100 million.

Summary

MR. MARTIN: Let's summarize. Let me tell you what I took away from this. The preliminary figures are that renewable energy tax equity was an \$11 billion market in 2016. That was a little over \$6 billion in wind and a little under \$5 billion in solar. The \$11 billion total was down from an adjusted \$14 to \$15 billion in 2015. On this call last year, we had said 2015 tax equity was about \$13 billion.

The reason for the smaller tax equity number seems to have been a drop in the number of utility-scale solar projects in 2016 compared to 2015. Both our tax equity investors said they see the market functioning normally despite the tax reform debate starting on Capitol Hill. The one change is they expect to see tax equity investors more interested in taking bonus depreciation in order to use up tax capacity at the higher tax rate in effect this year.

They see tax reform having a limited effect on the market: perhaps a little less tax equity might be raised in deals. Tax equity accounts for 50% to 60% of the capital cost of the typical wind farm and 40% to 50% of the cost of a typical solar project today.

In terms of noteworthy trends, Jack Cargas said he sees a trend toward more complex transactions. John Eber provided some very interesting numbers. Wind developers stockpiled enough turbine equipment in 2016 to justify a build out of anywhere from 30,000 to 58,000 megawatts of new wind farms, according to one estimate, and 40,000 to 70,000 megawatts, according to another estimate. That is in a market where the total installed wind capacity today is around 82,000 megawatts.

Turning to the bank market, what we heard was a significant drop off in dollar volume of transactions in 2016 compared to 2015. It was a 42% drop, according to Ralph Cho, from a \$60 billion North American project finance bank market in 2015, down to \$35 billion in 2016. There was only a 14% drop in the number of deals, from 160 down to 137. The reason was there were massive LNG projects in 2015 but not in 2016. Neither of our bankers expects to see LNG make a major comeback this year.

There were 50 to 60 active project finance lenders in 2016. Both bankers are expecting new lenders, particularly from Korea and perhaps other places in Asia, to come into the market in 2017. The bank market is expected to remain awash in liquidity.

Spreads are currently 162.5 to 200 basis points above LIBOR for plain-vanilla deals with good sponsors. That translates into a coupon rate of 2.6% to 3%, but then you need to add the cost of a swap. The bank market offers floating-rate loans. For merchant gas projects, the spread is 325 to 350 basis / continued page 16

liquids pipeline that carries refined petroleum products in the western United States, charge customers rates that include an income tax allowance even though, as a partnership, the company is not subject to income taxes.

A US appeals court told FERC to take another look at the matter in a decision released in July 2016. The case is called *United Airlines v. FERC*.

The issue is whether the approach FERC uses to calculate the regulated rates of return for transmission and pipeline companies already take into account taxes, so that any further recovery of taxes would be double counting.

FERC allows interstate pipeline and transmission companies to charge rates that are expected to earn them a reasonable rate of return on rate base as well as to pass through taxes and other operating costs. To determine the appropriate return, FERC looks at what investors are earning on comparable securities in the market. Investors focus on their after-tax returns. A company's share price in theory reflects the discounted after-tax cash flow that an investor will receive from owning the shares. The discount rate is the return that investors require to make the investment.

FERC said, "Because the return estimated by the [discounted cash flow] methodology includes the cash flow necessary to cover investors' income tax liabilities and earn a sufficient after-tax return, the Commission's policy of allowing partnership entities to recover a separate income tax allowance may result in a double recovery."

It asked for initial comments by March 8 and reply comments by April 7.

Pipeline and transmission customers are hoping that the inquiry will lead eventually to lower charges to move their electricity, oil and gas.

SOLAR AND WIND DEVELOPERS were helped by a US Tax Court decision in December.

The court suggested that property taxes a developer pays on land and interest paid on debt to buy the land must be added to basis in the project eventually built on the land. This means a higher investment tax credit on the project.

/ continued page 17

Cost of Capital

continued from page 15

points over LIBOR.

Debt service coverage ratios are currently 1.4x to 1.45x for wind, 1.3x for utility-scale solar, and 1.5x for rooftop residential solar. Contracted gas-fired power plants are 1.4x to 1.5x. Current advance rates on debt are 80% to 85% for contracted projects, but a little below 50% for merchant or quasi-merchant projects.

Turning to the term loan B market, we saw a significant rebound in that market in 2016. The numbers are \$11 billion in 2013 falling to \$9 billion in 2014, falling to \$3.3 billion in 2015, rebounding to \$11.6 billion in 2016. About 50% of the 2016 deals were merchant, and not just merchant gas-fired power plants, but also other types of merchant deals.

J-P Boudrias expects to see maybe \$5 to \$6 billion in B loan volume in 2017. The final volume will depend on how vibrant an M&A market there is. The spreads above LIBOR for term loan B debt fell from 2015 to 2016. We start 2017 with a spread of around 350 basis points for BB credits and 425 over for B credits. There is a 1% floor currently for LIBOR, but that may disappear during the course of the year.

About the project bond market, we heard that it, too, had a significant rebound in 2016. It is an investment-grade market. There were probably a half dozen syndicated deals in 2015, but close to a dozen large deals in 2016. There are a lot of active players, probably 25 as we enter the year, and eight to 10 anchor investors. There are five deals already in the pipeline in the project bond market compared to one at the same time last year. Spreads above 10-year treasuries are about 200 to 300 basis points. Ten-year treasuries are 2.4% at the moment, so that translates into a 4.5% to 5.25% coupon. ☺

Saudi Renewables: Reset and Launch

by Marc Norman, Richard Keenan and Helen Qian, in Dubai

Saudi Arabia, the world's largest oil producer, is relaunching its renewable energy program. Recent government communications suggest a determination to press ahead rapidly.

The first phase of procurements is due to kick off with issuance

of a request for qualifications on February 20. A request for proposals is expected to follow to qualified bidders on April 17. The plan is to award projects in September 2017.

Phase one will consist of 400 megawatts of wind capacity at Midyan, in the Tabuk province, and 300 megawatts of solar photovoltaics at Sakaka, in the Al Jouf province. It is not yet clear whether the capacity will be split into smaller projects. All projects will be procured on an independent power producer basis.

The procurements will be led by a new unit in the energy ministry called the renewable energy development office that has been tasked to drive the deployment of renewable energy across the Kingdom. The new office will report to an oversight committee, chaired by Saudi Energy Minister and chairman of state oil company Saudi Aramco, Khalid Al-Falih. The committee will bring together heads of key stakeholders in the Saudi energy sector, including King Abdullah City for Atomic and Renewable Energy (K.A.Care), the Electricity and Cogeneration Regulatory Authority, the regulator of the electricity sector, Saudi Aramco and the Saudi Electricity Company, the national utility.

Saudi Arabia also has its eyes set on nuclear, which it classifies as renewable energy. Al-Falih said at a conference in Abu Dhabi in January that plans are being drawn up for the country's first nuclear power stations. Two reactors with a combined capacity of 2,800 megawatts are currently in the front-end engineering and design stage.

These procurements are driven by the Kingdom's new target to procure 9,500 megawatts of renewable energy capacity by 2023 (which includes an interim target of 3,450 megawatts by 2020). Al-Falih said that development of this much capacity will cost between US\$30 and US\$50 billion.

The ambitious plans are part of the Kingdom's renewed effort to diversify its oil-dependent economy.

Unsustainable Oil Consumption

Saudi Arabia's domestic consumption of oil and gas, and its rising energy demand, are not sustainable. Approximately 90% of Saudi Arabia's revenue comes from oil, but the country currently burns a quarter of its total oil production. The Kingdom is among crude exporters struggling with budget deficits after oil prices languished for two years at less than US\$50 a barrel.

More recently, the country has been hit with oil production cuts, a concession that it was forced to make as part of a deal with its fellow OPEC oil cartel members. In January, the International Monetary Fund cut its growth estimate for Saudi Arabia because of reduced output levels. The IMF said that the

country's GDP will expand by just 0.4% in 2017, down sharply from its October 2016 estimate of 2%. Saudi Arabia can no longer afford to allow domestic consumption to eat into its export revenues.

Meanwhile, Saudi domestic energy demand has increased at an estimated 8% per year for the last three years, and is set to rise further. Saudi Arabia now consumes more oil than Germany, a country with a population three times the size of Saudi Arabia and an economy nearly five times bigger. A few years ago, Al-Falih observed that, if left unchecked, domestic oil consumption would reach 8.2 million barrels of oil a day by 2030. Until fairly recently Saudi Arabia oil production averaged around 9.22 million barrels a day. A widely circulated Citigroup report in September 2012 concluded that Saudi Arabia could cease to be an oil exporter by 2030.

Subsidized Electricity

Of the three million barrels of oil burned in Saudi Arabia each day, some 700,000 barrels are used to generate electricity. This makes the Kingdom the world's largest consumer of oil for electricity.

Like many countries in the Arabian Gulf, consumers in Saudi Arabia benefit from some of the world's lowest electricity prices due to government subsidization. State-owned oil and gas companies supply conventional power producers with cheap oil and gas at a fraction of the market price. Further subsidies are applied to the price at which electricity is sold by state-owned utilities to consumers. The average price of electricity sold in Saudi Arabia ranges from US1.3¢ to 6.9¢ per kilowatt hour. The International Monetary Fund estimates that energy subsidies cost Saudi Arabia US\$107 billion in 2015, or 13.2% of its gross domestic product.

Reform is clearly needed. Reducing subsidies and raising the price of energy might be the simplest way to restrain domestic consumption. However, this is a very sensitive area for any Middle Eastern government, particularly in the aftermath of the Arab Spring. Implementation of any energy price reform in Saudi Arabia is therefore likely to be very gradual.

A more viable solution to the Saudi energy crisis is diversification. The Kingdom currently produces very little renewable energy — renewable energy now represents less than 1% of total energy production — and there is no nuclear. Cheap conventional power has, until recently, proven to be a barrier to entry for renewable energy developers, but the cost of renewable energy has fallen dramatically in recent years.

On the solar side, Dubai's state utility grabbed headlines in 2016 when it secured a world record-breaking tariff of US2.99¢

/ continued page 18

The decision also suggests that the cost of meteorological data that wind developers gather to test whether a site is suitable for a wind farm are a cost of the turbines ultimately erected on the site rather than the land.

The case involved three partnerships that bought land and planted almond trees. The partners wanted to deduct property taxes on the land and interest on debt borrowed to acquire the land.

The court said that section 263A of the US tax code requires that the two amounts be capitalized, or added to basis, and the court went further to say they are added to the tax basis in the almond trees grown on the land rather than to basis in the land.

Section 263A requires the costs of "real or tangible personal property produced by the taxpayer" to be capitalized.

The power industry is accustomed to capitalizing property taxes paid during construction. The taxes in this case were paid over three years while the partnerships were growing almond trees. The court did not address whether the partnerships will be required to continue capitalizing property taxes after the initial growing period ends. However, its logic suggests that it was focused solely on property taxes paid during construction. It said that allowing a current deduction for the property taxes would violate a matching concept in the US tax laws that costs ought to be matched to the related income. The capitalized property taxes are a cost to put in almond trees that will produce income in future years.

Construction-period interest must be capitalized on any project that will cost more than \$1 million and that has an estimated "production period" of more than a year. The production period for "real property" starts when physical work starts at the site or at a factory. The production period for equipment and other "tangible personal property" starts when the accrued costs reach at least 5% of the total expected cost. It ends when the project is ready to be placed in service. */ continued page 19*

Saudi Renewables

continued from page 17

per kilowatt hour from a consortium of UAE-based Masdar and Saudi-based Abdul Lateef Jameel for an 800-megawatt solar photovoltaic project. Soon after, Abu Dhabi's state utility secured an even lower, albeit off-peak, tariff of US2.42¢ from a consortium of Japan's Marubeni and China's Jinko for a slightly larger project. Solar thermal has yet to take off in the Middle East. However, Dubai issued a tender for a 200-megawatt tower project in January, and low pricing on this project could spur growth of the solar thermal segment.

Bidding will start shortly in Saudi Arabia on the first round to deliver 3,450 MWs of new renewable energy projects by 2020.

While solar photovoltaics have dominated the headlines in recent years, dramatic price reductions have also been witnessed in the wind sector. Most notably, in 2016, Egypt's Ministry of Electricity secured a tariff of US4.7¢ per kilowatt hour from a consortium of France's Engie, Japan's Toyota and Egypt's Orascom for a 250-megawatt wind project.

Renewable energy has, therefore, become an attractive option for Middle Eastern governments.

Relaunch

Plans to launch a renewable energy program in Saudi Arabia have been long in the making. K.A.Care was established in 2010 to oversee realization of the country's renewable and nuclear energy ambitions. In 2012, it launched an ambitious renewable energy program. However, since the issuance of a white paper on the program's tendering procedures in March 2013, K.A.Care's program has remained stalled.

It has been widely reported that the K.A.Care program was stifled by bureaucratic disagreements over the scale and

ownership of the program and how it should be implemented. A number of Saudi government entities have a significant say in energy policy. These include the Saudi Electricity Company and Saudi Aramco. A regime change in 2015 further complicated matters. For the last four years, the renewable energy industry has been waiting for renewed direction from the Saudi government.

This renewed direction now appears to have come. In April 2016, the influential Saudi crown prince unveiled plans, as part of a "Vision 2030" policy paper, to develop 9,500 megawatts of renewable energy capacity by 2023. This announcement, made against the backdrop of a major shakeup within the Saudi govern-

ment, was significant. The development of 9,500 megawatts of capacity in six years is an ambitious target, but perhaps more realistic than the headline-grabbing targets set by K.A.Care a few years ago. The K.A.Care program contemplated the development of 41,000 megawatts of solar capacity by 2032. This would have required the development of more than 2,000 megawatts of solar power annually over a 20-year period. The

new, more modest target is altogether more achievable.

Recent announcements by the Saudi government will reassure industry players that the government is serious about its renewable energy program. The entire scheme is projected to cost between US\$30 and US\$50 billion, with industry players estimating that the first round of 400 megawatts of wind and 300 megawatts of solar photovoltaic capacity could cost around US\$700 million. Major developers, such as Abdul Latif Jameel Energy, ACWA Power and Enel SpA, have already expressed an interest in the plans, which seem to have been received with genuine optimism by industry players.

Nuclear Power

The January announcement may also have come as a surprise to those who have been skeptical about the potential for nuclear power in the Kingdom.

Ever since 2011, when K.A.Care announced its intention to develop 16 reactors by 2030, at an estimated cost of US\$7 billion per plant, the development of Saudi's nuclear energy program

has been sluggish. Last year, the country's deputy economic minister (and former K.A.Care representative), Ibrahim Babelli, cast doubt on whether Saudi Arabia would proceed with its nuclear plans. Babelli's view was that nuclear power plants were not needed in Saudi Arabia and that solar power would be preferred.

The January announcement is more encouraging. Al-Falih indicated that there would be "significant investment" in the nuclear sector, and revealed that Riyadh is in the early stages of feasibility and design studies for its first two commercial nuclear reactors, which will total 2,800 megawatts.

The Saudi government has signed cooperation agreements with countries able to build nuclear reactors, such as France, Russia and South Korea, and discussions with China are ongoing. However, Al-Falih did not provide cost predictions or a timeline for the planned investments. It remains to be seen whether nuclear power will be a viable option for the Kingdom's energy mix.

Financing Options

New sources of liquidity will need to be tapped to finance the ambitious build out of new renewable energy projects.

Developers of conventional IPP facilities have relied on conventional banks and Shari'ah-compliant financial institutions for financing as well as on direct loans and guarantees from export credit agencies. With the funding constraints imposed by Basel III and other international banking regulations, the pool of liquidity from traditional sources is not as deep as it was a few years ago.

These liquidity constraints have forced developers in the Middle East to turn to other markets, such as China. The most recent power project financing to close in Dubai, for the Hassyan conventional IPP, included significant contributions from Chinese banks. Marubeni and its Chinese partner, Jinko Solar, may seek to finance the Sweihan solar IPP at least, in part, with debt sourced from Chinese financial institutions. Recent moves by China to restrict outbound foreign investment in an effort to shore up the renminbi and maintain foreign exchange reserves raise questions about whether Chinese banks will be able to continue to support IPP developers in the region.

Many Middle Eastern countries are now running large budget deficits at the same time that the planned infrastructure spend of these governments is increasing.

This begs the question of where the funding will come from to pay for the new infrastructure. Last year, Saudi Arabia raised US\$10 billion from a consortium of global / *continued page 20*

The case is *Wasco Real Properties I, LLC v. Commissioner*.

MUNICIPALITIES hiring private contractors to operate municipal facilities now have more flexibility.

The IRS revised guidelines for management contracts with private contractors in January to address questions municipalities have been asking since the original guidelines were issued in August 2016. The new guidelines are more detailed.

Municipalities that issue tax-exempt bonds to finance schools, roads, hospitals and other public facilities must be careful not to allow more than 10% "private business use" of the facilities or the bondholders could end up having to pay taxes on the interest they receive on the bonds.

Hiring a private company to operate and maintain a public facility can be private business use, depending on the terms of the management contract.

This is potentially an issue for any facility owned by a municipality. However, it is not an issue for facilities that are financed with "private activity bonds." Such facilities are already considered to have too much private business use, so the content of a management contract with a private party is irrelevant.

The latest guidelines are in Revenue Procedure 2017-13.

A management contract with a private party will not be considered "private business use" of a public facility if the contract is purely for incidental services, like janitorial services, office equipment repair, billing, payroll or similar tasks.

It is also not private business use for a private party to manage utility-type property if the private party is merely reimbursed for its direct expenses plus reasonable administrative overhead.

It is not private business use for a private party to provide services before a project is placed in service. An example is construction management services.

In all other cases, the / *continued page 21*

Saudi Renewables

continued from page 17

banks. This was the first debt issuance by the Saudi government in 25 years. A few months later, the Saudi government raised a further US\$17.5 billion through a sovereign bond offering, the largest-ever bond sale by an emerging-market nation. Further debt issuances and bond offerings by Saudi Arabia and other Arab Gulf countries are expected in 2017.

Most international banks and financial institutions have limits on their exposure to Gulf Cooperation Council member states (Saudi Arabia, Kuwait, the United Arab Emirates, Qatar, Bahrain and Oman). These limits are usually reviewed each year, but are not made public. Over the last few years, a number of international banks are rumored to have neared or reached their limits for certain countries in the GCC and elsewhere in the Middle East. Falling credit ratings of some of these countries and the fact that the governments themselves are now competing for the same potential credit pool are not helping.

The hope is the debt capital markets will develop enough to replace the dwindling available bank debt. A project bond market has been slow to develop in the Middle East, in part because cheap long-term debt was available from banks. Bond investors are increasingly looking at emerging markets for yield. Recent sovereign and corporate bond issuances in Saudi Arabia, the UAE, Oman, Kuwait and Egypt demonstrate significant appetite for debt capital markets in the region.

Since refinancing of Abu Dhabi's Shuweihat 2 independent water and power project with a project bond in 2012, a number of project financings in the Middle East have been structured to allow for refinancing using project bonds. Apart from a few notable exceptions in the oil and gas sector, project bonds have not been used so far to fund greenfield projects in the Middle East.

The recent and rapid growth of the "green bond" market could prove to be a game changer. Green bonds are bonds issued at the level of the parent corporation whose proceeds are invested in projects that contribute to an environmentally friendly energy transition, including renewable energy. Green bond issuances worldwide are expected to exceed US\$100 billion in 2017, up from US\$11 billion in 2013. Green bonds offer the same returns for investors as conventional bonds or Islamic bonds known as sukuk. They have been used to finance greenfield renewable energy projects in Europe and Asia. Projects in the Middle East

are often financed on the back of strong sovereign balance sheets, and risk allocation embodied in Middle Eastern projects, particularly in the power and water sector, compares favorably to other regions. Green bonds may provide some of the additional liquidity needed for the Saudi renewable energy sector.

One of the features of the Saudi conventional IPP program has been the significant equity stake that the Saudi government-owned entity takes in each project company. However, if the recent procurement by the Saudi Electricity Company for the 20-megawatt Al-Jouf and 80-megawatt Rafha solar photovoltaic IPPs are anything to go by, the Saudi government is not planning on making equity contributions to renewable energy projects. There are successful regional IPP models that do not include government equity stakes.

However, this means that a deeper pool of equity investors will need to be tapped into. Any equity investors new to the region or the Saudi market will focus on the level of potential equity returns and their ability to exit projects. Both have to be in keeping with international norms.

Developers may try to fund their equity requirements by raising capital from mezzanine finance providers and the equity capital markets.

Although Saudi Arabia seems determined to press forward quickly on its renewable energy program, past experience leaves room for skepticism. More details about the program will be needed before developers can bid. For example, details are still needed on any local content and local employment requirements. Such requirements were a cornerstone of the K.A.Care program, which placed great emphasis on in-country manufacturing and industrialization. They were also a feature of the Al-Jouf and Rafha solar photovoltaic IPPs. At a press conference in early February, Al-Falih said that "The terms of renewable contracts will be motivating so that the cost of generating power from these renewable sources will be the lowest in the world."

Saudi's renewable energy market is still in its early stages. Any imposition of local content and local employment requirements could significantly weigh on project costs and inflate electricity tariffs. Procuring authorities in Dubai and Abu Dhabi did not impose such requirements. ☉

Negotiating Corporate PPAs in the Middle East and Africa

Sizable reductions in the cost of solar equipment have created countless opportunities for developers operating in the Middle East and Africa to enter into power purchase agreements with commercial and industrial enterprises and to provide electricity at a lower rate than the local utility.

Solar pricing on government tenders continues to hit record lows, raising questions about long-term market sustainability. This is causing some developers to try to secure deals with corporate offtakers directly.

However, developing a commercial or industrial solar project in any emerging market is challenging. PPA negotiations with C&I offtakers, who often have either limited or no experience in buying electricity, and maybe no project finance experience, can be extremely time consuming.

A group of energy executives actively involved in solar C&I development in the Middle East and Africa talked at a Solarplaza conference on “Unlocking Solar Capital” in Kenya in November about their experiences.

The group was Ira Green, managing partner of GG Energy, Jeremy Crane, CEO and founder of Yellow Door Energy, Raoul Ilahibaks, senior associate, renewable energy, at ResponsAbility, Roberto Martin, business development manager for East Africa at SolarCentury, and Matthew Tilleard, managing partner of Cross Boundary. The moderator is Marc Norman with Chadbourne in Dubai.

MR. NORMAN: Roberto Martin, as a business development executive working for a solar power plant developer, you are in close contact with C&I offtakers. I suspect one of the very first questions they ask you is, “Is solar actually going to work at my factory? I do not know the technology. Can I have confidence that the solar installation will not disrupt our company’s operations, and that the savings on electricity costs will be worthwhile?”

MR. MARTIN: Yes, in the initial stages, these are exactly the questions we get.

Another typical question is, “I see solar working in places like Europe and Latin America, but is it really working in Africa? There is no track record.” Over time as we build / *continued page 22*

IN OTHER NEWS

management contract must comply with the following guidelines to avoid being labelled a form of private business use.

The compensation paid to the private party must be reasonable in amount. Thus, the municipality should not pay more than other parties are charging for the same services. The amount does not have to be the lowest bid.

The contract cannot tie the contractor’s compensation to profits or losses on the project being managed. Thus, the contractor cannot share in profits. It cannot be paid less or have its compensation deferred if there are losses. However, a penalty for failure to keep expenses below specified targets is okay. The penalty amount should be set in advance in the contract. It can be a range of dollar amounts and expense targets.

The contractor can be paid any mixture of the following three kinds of compensation.

It can be paid a capitation fee, meaning a fixed charge for each customer served. A capitation fee can include an adjuster that would add up to another 25% to the original base fee to protect the contractor against an unforeseen workload.

The contractor can be paid a periodic fixed fee, meaning a fixed charge for each time period.

Or it can be paid a per-unit fee, meaning a stated dollar amount for each unit of service provided. An example is a fixed charge for each car allowed on a toll road.

All three types of fees can be adjusted by an inflation index or other outside index. The contractor can also receive payments on top of these fees that are tied to the quality of services, performance or productivity.

Payment of fees can be deferred due to insufficient cash flow, but only if the contractor is paid at least annually, interest or late payment fees apply to the deferred amount, and the deferred amount, plus interest or late payment fees, must be paid at the outside within five years after the original due date.

The contract cannot have / *continued page 23*

Corporate PPAs

continued from page 21

a track record, confidence in solar will increase and those questions should be less common.

The next stage is when customers start saying, “The technology is working. I see the numbers. How can you finance the solar system?” That is when we need to think about structuring a financing product. We see an increasing number of financing companies coming into the market, and we are seeing a lot of growth in this segment.

When we start looking into PPA terms, one of the key words for potential customers is “flexibility.” A corporate PPA is a different model. We are not talking to state-owned utilities with tried, tested and bankable PPA models and standardized processes for project procurement. We are talking to a wide array of customers from various sectors, often with very different profiles. So a solution that works for one customer may not work for another. In this context, flexibility is key.

Some customers only look at long-term savings, while others focus on short-term. This affects expectations on the PPA term. Customers that do not trust the technology tend to want very short PPAs — perhaps one, two or five years. The flexibility that we are able to offer is key to making this model work.

MR. NORMAN: If a developer wants to raise financing for these projects, the PPA must be long enough to support the debt. Ideally, you want a PPA with a term of at least 15 years. How do you get around this problem with potential customers who are only willing to commit for one to five years?

MR. CRANE: Commitment is always an issue in every aspect of life. [Laughter] Solar has a long-term payback, depending on the cost of power. In Jordan, where utility prices are high, we had the benefit of being able to generate high returns with a relatively short contract. The flexibility that an offtaker needs varies from one business to another.

For example, what flexibility does a shopping mall need that hopefully will be operating for a couple decades? Maybe the owner will want to add another floor? Then it is flexibility about removing and reinstalling the solar system. If you are dealing with a commercial enterprise, the flexibility could be something like a roof replacement, and that can be dealt with contractually. We will promise to remove the panels and put them back on the roof once over the life of the contract.

In a place like Kenya where electricity prices are fairly low, I cannot see a financed solution — a PPA, a lease, or whatever you

call it — that does not require a customer to make a long-term commitment. The cost of the solar project takes time to pay back. The customer has to make a choice: “Do you want to save the maximum dollars in year one, and then take a long commitment, or are you willing to save very little, maybe nothing, and have a shorter-term commitment?”

MR. TILLEARD: People do not have problems with the length of the contract per se, but they have problems with the practical implications. What happens if I move site? What happens if the currency changes by 400%? What happens if the electricity tariff changes? These concerns do not rule out a long-term contract. We have to come up with the contractual structures that address these practical concerns.

We are fully focused on C&I solar. We are building and operating assets in Africa only. We spend all our time thinking about how can we structure these contracts to address these practical concerns.

Opportunities

MR. NORMAN: Ira Green, you deal with private mining companies. Mining operations are sometimes unpredictable. For instance, work in a mine may be suspended when commodity prices fall. This is an issue from a financing perspective. How do you work around such challenges?

MR. GREEN: We focus on mines that have a long life ahead of them. In some cases, the projected remaining life is as long as 35 years. They are some of the deepest and richest mines in terms of mineral ore.

I just want to bring in another point here, because we talked about PPA pricing being important. It is important, but with many C&I customers, particularly in Africa, there are two other big issues. One is power quality. The other is availability and stability. If an offtaker in Africa is connected to the grid, power is often weak. If the customer is at the end of the grid, it will likely have issues with voltage fluctuations.

The integration of a solar photovoltaic system, if structured properly, can alleviate a lot of those issues and provide offtakers with a better quality of power at a competitive price. That is something that is very important for the mining industry. People need to take that into consideration when assessing the terms of these contracts.

MR. NORMAN: Raoul Ilahibaks, ResponsAbility helps developers explore investment opportunities in C&I solar. We often focus on how much customers can save against the price charged by the local utility for electricity, but where there is no grid, solar is

often competing against diesel. The potential for C&I solar is likely to vary greatly from country-to-country, and from one site to another. Where do you see the most potential?

MR. ILAHIBAKS: It depends on the state of the local utility, electricity prices, and connectivity.

Take Rwanda, for example. You have a lot of diesel being imported into the country, and many large companies are still using diesel generators as a backup. It makes sense in Rwanda to displace some diesel with solar.

In Tanzania, where electricity prices are highly subsidized and the national utility is weak, solar photovoltaic systems are being offered as an off-grid solution: to mining companies, for example.

Interest in corporate PPAs is growing in the Middle East and Africa.

It depends on the country, and the reliability of the grid. It also depends on what the customer is really looking for. Is the customer looking for more reliable power or is it focused mainly on the cost?

MR. NORMAN: To what extent are offtakers willing to pay a premium for storage to have stability of electricity supply?

Rwanda is one of those markets where the grid tends to go off several times a day, not necessarily for very long, but between one and two hours a day.

Matt Tilleard, Cross Boundary has just signed a PPA for a fairly big solar C&I project in Rwanda. Was the offtaker on that project interested in storage, notwithstanding the cost? What is the market for storage?

MR. TILLEARD: I think storage is too expensive. Storage is a potential future technology, notwithstanding that we have two solar battery PPAs operating in Kenya. They are for a particular application. They are for remote, off-grid safari lodges where diesel fuel is trucked in across ecologically sensitive land, and people are paying US\$1,500 a night for a / *continued page 24*

IN OTHER NEWS

a term longer than 80% of the expected economic life of the facility or 30 years, whichever is shorter.

The municipality must retain a “significant degree of control” over use of the facility. It must approve annual budgets and capital expenditures, dispositions of any parts of the facility, and the rates charged for the electricity, steam or other output.

The municipality must bear the risk of loss to the facility from a casualty or other event outside the control of the contractor.

The contractor cannot have a role in the project company — for example, director positions that give it more than 20% of the vote or a board role for the contractor’s CEO or board chairman — that might undermine the ability of the municipality to enforce the management contract.

If any of these required contract provisions is materially amended, then the contract must be retested as of that date.

MASTER LIMITED PARTNERSHIPS must adapt to new guidelines.

The IRS settled in January what types of minerals and natural resources businesses may operate as master limited partnerships or MLPs.

Companies that are operating currently as MLPs, but will not be able to do so in the future, will have 10 years to adjust.

The guidelines are in the form of final regulations. They interpret section 7704(d)(1)(E) of the US tax code. They were published on January 24, four days after White House chief of staff Reince Priebus sent a memorandum to all federal agencies imposing a freeze on any new regulations that had not been published yet in the Federal Register.

An MLP is a partnership whose ownership interests are traded on a stock exchange or secondary market. The United States usually taxes publicly-traded companies as corporations. However, it makes an exception for partnerships that receive at least 90% of their gross income each year from passive / *continued page 25*

Corporate PPAs

continued from page 23

tent. Customers who pay for this type of camping experience do not want to listen to a diesel generator. [Laughter] In that type of scenario, storage makes sense.

For our Rwanda project, storage does not make sense yet. The Rwanda project is for a large multinational company. The project is small at around 1.5 megawatts, but we will be adding close to 1% of the generating capacity of the whole Rwandan grid.

The nice thing about the PPA model is that when storage does make sense, we will be the first people there, and we will be able to go back to all of our existing customers and add storage to their existing solar systems. Storage will help increase reliability and power quality when the time comes.

Pricing

MR. NORMAN: We have talked about reliability as a selling point. However, the ultimate question is price. Roberto Martin, how much of a discount do you need to show from the local electricity price to have a sale?

MR. MARTIN: For perhaps 95% of customers in Kenya, the key motivation for looking at solar is cost savings.

If I could first, let me add to what was said earlier about battery storage. We are currently installing batteries on one of our solar photovoltaic systems. I agree that it is not economically viable if the goal is to compete with the grid, but it is probably competitive with diesel generators. At SolarCentury, we believe solar plus storage will be economic within fewer than five years. Once we integrate batteries, we will be solving more problems than we are now.

Another challenge we have with corporate offtakers in Africa is the take-or-pay clause in the PPA. They understand the concept, but the problem is how to make it workable from an operational standpoint. Sometimes a business may not operate on the weekend, meaning that there is little-to-no need for electricity during such time. A customer may also have seasonal operations. Without storage, the offtaker will have to pay for electricity that it does not need. That is a big challenge for many businesses. One solution is including batteries. Another solution would be for governments to implement net metering regulations: if an offtaker is permitted to feed excess power to the grid and then take it back when needed, this makes solar much more compelling.

MR. TILLEARD: Returning to pricing, when we first did the model for our fund, we thought we would tell customers you are

paying 12 US dollar cents in Kenya for your electricity, which is the price for most large industrial customers, but you are running on diesel 20% of the time, and diesel costs this much, so your weighted average cost of electricity is X. But by that stage, the potential customer is already bored.

Our customers are not really interested in the weighted average cost of the grid versus diesel. It has been very difficult to make the case on this. What we have found is that we generally need to be 20% cheaper than the grid. Until that point, you are just wasting a lot of sales time and effort.

MR. NORMAN: Jeremy Crane, customers ideally want to set a fixed tariff throughout the term of the offtake agreement, but this may not always be workable. To what extent are you managing to build some escalation into your PPA tariffs, and how is it structured?

MR. CRANE: These are very interesting questions. On savings, I agree: 20% is a good number. If you can hit that, customers get interested. If you are talking 10%, is it worth their time? Depending on the size of the customer, you may be talking about US\$1,000 a month. An important CEO probably does not worry about such small amounts.

With regards to price escalation, the power industry is in a price compression phase. I am talking globally. In our backyard in Dubai, we are seeing ridiculously low prices coming in for power generation. The cost of power generation will continue to fall during our lifetimes. There will always be a premium paid for grid interconnection, and we will pay that as long as it is less than the cost of batteries.

As soon as batteries become economical, then maybe the grid is no longer relevant to us and our industry. In the meantime, we pay. As a consumer at my house, I pay for the generation that happens a long way away, and I pay for the transmission to my house. If I was to price to a consumer today at, say, 20% off 12 US dollar cents a kilowatt hour and I was to put an escalator in there, expecting the customer to follow inflation, I am going to be moving that customer out of the market of economic benefit as I move forward, and that will put my contract with that customer at risk. So I do not think that is a viable scenario. In fact, in many situations, we price relative to the grid. In case grid prices go up or down, we will follow the grid pricing.

MR. NORMAN: Raoul Ilaahibaks, another price-related issue that worries offtakers in the Middle East and Africa is currency risk. If an offtaker is being asked to sign up to, say, a US dollar tariff payable in a non-pegged local currency, then its key concern is a scenario where the local currency plunges against the US dollar

thereby increasing its solar energy charges to a level that may be no longer viable.

Some of the offtakers you and your clients deal with are local enterprises. They will be getting their revenues in local currency, and so they will want to deal exclusively in local currency. When you are dealing with big multinational companies, perhaps mining companies, they may be getting some of their revenues in US dollars and will be happy to pay you in US dollars. Do you have any thoughts on currency-related issues that one typically encounters in these deals?

MR. ILAHIBAKS: Offtakers can be separated into three different buckets: the big multinationals, the local companies that have hard currency revenues, and the local companies that only have local currency revenues.

The multinationals are part of a larger organization and can absorb currency risk. For these companies, agreeing to a hard currency-denominated tariff is less likely to be an issue.

But if you look at the other two buckets, currency is a big issue. And this is problematic because that is where the majority of the market is. In order to unlock the potential of these two buckets, we need to find a solution to the currency issue.

We are looking at local currency lending. We need more participation from local lenders in the market, whether from local banks or entities like GuarantCo, to provide local debt financing.

The low-hanging fruit is the multinationals, but to capture the bigger part of the C&I market, we need to find a solution for currency risk. I believe institutions like TCX can help with these currency issues, but local banks need also to play an active role.

MR. GREEN: I agree. There is another complexity that affects all three of your buckets and that is the regulatory framework for payments.

In certain countries you cannot be paid in foreign currency. For example, if you have a project in Tanzania, you are not permitted to be paid in any currency other than Tanzanian shillings. So you would have to seek a currency hedge — which the local banks or your lender can provide — but that adds to the cost.

Off Balance Sheet

MR. NORMAN: There is another big topic: deconsolidation.

Often when you start off negotiations with corporate offtakers, one of the first things that an offtaker will tell a developer is: “We do not want this project to be on balance sheet. That is why we are coming to you. Otherwise, we would have done the project ourselves, or procured it on an EPC / *continued page 26*

sources, like interest or dividends, or from activities tied to minerals or natural resources. Such companies are able to operate without having to pay corporate income taxes. Their income is taxed to the owners directly.

The regulations explain how closely tied a partnership’s activities must be to minerals or natural resources to produce good income.

The IRS had been fielding a growing number of requests for private letter rulings from companies that provide services to the oil and gas trade and want to operate as MLPs. It put a hold on any further rulings in February 2014 while it evaluated where to draw the line. For example, is a business that sends catering trucks to sell meals to workers at gas fracturing sites closely enough related to production of natural gas to be able to operate as an MLP? The agency lifted the hold in early March 2015 and said that regulations would follow.

The regulations treat income as qualifying income only if it is from engaging directly in “exploration, development, mining or production, processing or refining, transportation or marketing” of minerals or natural resources or from providing a limited class of services to companies that are directly engaged in such activities.

The eight direct activities represent various stages from extraction of minerals and natural resources through eventually offering of them for sale. Converting minerals or natural resources into something else through “manufacturing” goes too far.

The vast majority of comments the IRS received after proposing where to draw lines in 2015 addressed what should qualify as “processing” or “refining.”

“Processing” may cause a substantial physical or chemical change. However, coking of coal or activated carbon does not qualify. These are manufacturing processes that create a new product rather than mere processing. The regulations include a list of 35 qualifying products that may be produced by refineries and still be considered “processing.” The list / *continued page 27*

Corporate PPAs

continued from page 25

basis. We therefore want you, the developer-financier, to do the project for us, and structure things so that the project is not required to be consolidated on our books.”

We spend a lot of time as lawyers working with developers and their accountants to structure the contractual arrangements so that they are off balance sheet.

Devising these type of structures can be challenging because deconsolidation requirements can sometimes be inconsistent with typical contractual structures and terms. Also, the accounting rules are constantly evolving.

Consider the following example. A developer is dealing with a potential offtaker that will not do a deal unless the project is off its books. Assume the potential offtaker is accounting under full International Financial Reporting Standards. The developer has typically structured its offtake agreement with corporate offtakers as an operating lease, rather than an on-balance sheet finance lease, to avoid consolidation. Depending on how the developer's operating lease is structured, it may soon be impossible for the developer to offer an operating lease to this type of offtaker.

From January 2019, IFRS 16 will require all leases, with limited exceptions, with a term of more than 12 months to be brought onto the lessee's — in this case, the offtaker's — balance sheet. This includes operating leases. IFRS 16 defines a lease as a contract, or part of a contract, that gives a lessee the right to use an asset for a period of time in exchange for compensation. Determining whether an arrangement is a lease hinges on whether a lessee controls the use of the asset. The focus is on whether the lessee has substantially all of the economic benefits from use of the asset, and whether it directs the use of the asset throughout the period of use. In each case, assessing control is a matter of fact based on an analysis of the particular contractual arrangements. So an operating lease model may or may not be viable, depending on whether the contractual terms grant control to the offtaker.

If, for whatever reasons, neither a PPA nor a lease is viable, then the developer should consider alternative offtake structures. We are working with developers on energy savings contract models, where the developer effectively acts as a service company.

I know that for some offtakers, deconsolidation is a really important issue, and that any risk of the project being consolidated on its balance sheet is a non-starter. Ira Green, what has been your experience?

MR. GREEN: It is the biggest stumbling block that we face in the C&I space. You have to figure out a bespoke solution for each customer.

Regulatory constraints also heavily affect structuring. In some cases, you may want to structure a joint venture with the offtaker so that the project is considered a self-generation project. If you operate in a market where the state utility is the single buyer and distributor of electricity then, as a pure independent power producer, you will likely run into issues. If you create a joint venture-type structure, you can avoid some complications.

That is one solution. Otherwise, I am beginning to hear that there are potential funders, development finance institutions and the like, that might be willing to help and take some degree of balance-sheet risk. They have sufficient resources to do that in order to facilitate the deals. That is another potential avenue.

MR. NORMAN: Matt Tilleard, I think I have a flavor already of your views. To summarize quickly: when you first started off, you realized that deconsolidation was an issue and you, like us lawyers, had a very big think about structuring. But you then came to the conclusion that too much reflection was perhaps leading to over-complication.

MR. TILLEARD: We have spent a lot of time in conference rooms trying to design the perfect product that would solve the deconsolidation issue and, honestly, customers have never brought it up with us. Not once. And we are dealing with sophisticated, large customers.

We do have structures in our back pocket that, under Kenyan law, Ghanaian law or Rwandan law — the countries where we already operate — would address these constraints. But for now consolidation has not been a problem; and the tradeoff is simplicity.

Deconsolidation is an interesting point as a financier. We are already trying to convince people to do something that they have never done before. No one in Africa ever got fired for sticking with the grid and diesel. Now they are going to go do something entirely different. They are going to add solar into their energy mix.

When you give a potential customer five options, you say, “We can do it this way, or that way. We can toggle this or that,” the thing they choose is to do nothing. So what we have found works best is to say simply: “This is the deal. It is a simple PPA. You just buy power from us. We take the risk.”

MR. GREEN: The size of opportunities and projects may be a factor. When you are dealing with projects that are sub-10 megawatts, then you may have less of an issue. It becomes a big issue

when you are dealing with a project that is 20, 30, or even 50 megawatts.

MR. TILLEARD: That's fair.

MR. CRANE: We have actually seen deconsolidation come up on small deals too: one megawatt, two megawatts.

Like Matt Tilleard said, you need to adapt to your customer's needs. With now 30 megawatts of customers under our belt, we have seen a lot of different requests, and what is important is the flexibility to be able to provide a solution that meets the customer's needs.

You need to hear them. You need to respond to them. But at the same time, you need standardization. So it is a bit of a double-edged sword. But we certainly, with the support of Chadbourne, have found solutions in a multitude of different scenarios. It just takes time.

Other Structuring Issues

MR. NORMAN: We have touched upon two fundamental, but different, structuring issues. The first is deconsolidation, which certain offtakers require. The second relates to the regulation of electricity markets and the so-called single buyer model.

In a number of electricity markets, the local or national utility has a monopoly on the purchase of electricity. Unless there is carve-out regulation for, say, self-generation, net metering or wheeling, a developer cannot structure its offtake agreement as a power purchase agreement because supplying electricity at retail to an end user is illegal. In this context, the first structuring challenge is how to get around the restriction on supplying electricity. While each jurisdiction has its own peculiarities, there are sometimes ways to structure around these restrictions.

The main fallback options are solar leasing agreements and energy savings agreements.

There is another point that I wanted to touch on, and one that often emerges as a contentious issue in negotiations with corporate offtakers: change-in-law risk. If there is suddenly, say, a major increase in a fee or a tax, and this has a material impact on the developer's costs, then the deal economics have changed. It could also apply to the offtaker. For example, a new tax is introduced that has the effect of materially increasing the offtaker's monthly energy payments.

In a government-procured independent power project, the state utility will typically protect the developer, to varying degrees, from potential adverse effects of a change in law. This is primarily because the state utility recognizes that by being government-owned, it indirectly

/ continued page 28

came from the US Energy Information Administration.

"Transportation" — another permitted MLP activity — means doing the physical work of moving oil, gas or other minerals or natural resources by pipeline or marine vessel.

Liquefying natural gas to produce LNG, or regasifying it to turn it back into natural gas, qualifies as a transportation activity.

Producing ethanol or biodiesel does not qualify since they are not produced from depletable minerals or natural resources. However, an MLP can act as a blender of ethanol or biodiesel with gasoline or other transportation fuels without being considered to have moved too far downstream as long as the ethanol or biodiesel is not more than 20% of the total volume of the blended fuels. There is a limit of less than 5% by volume on an MLP adding other items to natural gas or oil products.

In general, any activity that involves retail sales or distribution to retail sellers or end users goes too far. Thus, for example, supplying gasoline to service stations does not qualify. However, there are exceptions for certain bulk and wholesale sales to end users, such as supplying fuel to electric utilities. A special provision allows an MLP to supply liquefied petroleum gas, or LPG, directly to consumers.

An MLP can hold passive interests in minerals. Examples are royalty interests, profits interests, rights to production payments, delay rental payments and lease bonus payments.

A number of paper companies had been considering converting parts of their operations into MLPs. The regulations make clear that converting timber into wood chips, sawdust, untreated lumber, veneers (without any substances added), wood pellets, wood bark and rough poles is an acceptable activity for an MLP. However, it goes too far to produce pulp (at least if chemicals are added), paper, paper products, treated lumber, oriented strand board, plywood or treated poles.

/ continued page 29

Corporate PPAs

continued from page 27

has control over a change in law.

Sometimes you will have a risk-sharing arrangement where the developer takes the hit up to a pre-determined amount — like a deductible portion under an insurance policy — with anything above being assumed by the state utility.

Otherwise, a distinction may be drawn between change in law whose effect is of a one-off versus a continuing nature. If the effect is a one-off, then the developer would get a lump-sum payment as compensation. If the effect is continuing then the tariff under the offtake agreement would be adjusted to compensate the developer for the remaining term.

A corporate offtaker may struggle to assume change-in-law risk. This is something that generally leads to heated discussions. Ira Green, is this something that you come across a lot with your offtakers?

MR. GREEN: Yes. What we find is that offtakers generally do not want to take any change-in-law risk. They believe it should be the developer's risk. We work closely with our insurance consultants who can structure a political risk insurance that will cover this type of change-in-law risk.

MR. TILLEARD: We use political risk insurance, but it really only covers us where due process has not been honored.

If taxes go up over time, or there is some other change in law that disadvantages us, then that is something that we need to resolve. I have not seen great contractual solutions. In the US, it is pretty standard to force both parties to come to the negotiating table and, in theory, the contract parties figure something out. I am interested in hearing about different approaches.

This is the way we currently play things: these are 25- to 35-year assets, and the contracts are typically 15 years long. If a change in law arises and we are forced to the negotiating table, then we would look to extend the contract to preserve economic value.

MR. NORMAN: That seems to be where a number of

developers are landing: take a bit of a soft approach and say, if there is a change in law and the economics have materially changed, then the parties will come to a negotiating table and try to put themselves back into the position that they were in when they signed the offtake agreement.

If you put on the hat of a developer or lender that focuses on government-procured IPPs, you may view this arrangement as too uncertain. This is perhaps one of the prime examples where developers and lenders need to shift their minds away from that government-procured stand-alone IPP mentality toward a more flexible, although perhaps less certain, universe.

We were touching upon the issue of deconsolidation. One of the things we did not discuss is payment security. In order for the developer to be able to raise limited recourse debt financing, a government would typically be expected to offer a sovereign guarantee. And so when dealing with corporate offtakers, developers tend to ask for a parent company guarantee. Any guarantee is a contingent liability on the books of the offtaker's parent. That would contradict deconsolidation objectives. Therefore, C&I offtakers are often not willing to give the type of payment security that project financiers would typically expect, and sometimes may not be willing to provide anything at all.

When you look at the whole picture and compare, on one hand, the government-procured project with a sovereign guarantee and change-in-law protections and, on the other hand, the privately procured project with very limited or no payment security where change in law is left fairly open, you realize that we are talking about very different animals.

The reality is that project risks on C&I projects are often mitigated by aggregating into a wider portfolio. On a stand-alone basis, corporate PPAs present more risk than a state utility PPA. Perhaps this is one of the key reasons why — to the dismay of C&I offtakers — corporate PPAs cannot be priced as low as state utility PPAs, especially those back-stopped by a DFI. Are you developers having any success getting that message across to potential customers?

MR. TILLEARD: It largely comes back to price. When people start quoting really high electricity prices charged by utilities in certain markets, then comparing the prices to tariffs bid on government-procured solar projects, it seem like the C&I market segment is a bonanza: "We can

Developers need to be 20% cheaper than the grid to attract customers.

do solar for six cents, but actually the electricity price is twenty-two cents. We are all going to get rich.” [Laughter]

Actually, it is not like that. In certain markets, it may be a little bit, but not a lot. This is because we are talking about very long contracts involving a lot of uncertainty about how things will play out.

You need to provide a significant incentive to a corporate customer to bring it on-board, to do something that it has never done before within its factory operations, for the general manager of the plant to say he is willing to take the risk. There are elements like change in law, or a dramatic change in the local currency, that are very difficult to control.

It works when you can give a very strong value proposition on price, but not where the cost savings are marginal.

Making the Sale

MR. CRANE: I think you need to look at what the alternatives are for the customer. You are dealing with an entity that is consuming a lot of power and paying a lot of money. The people that you are talking with understand that solar is going to save them in the long run. They have three options.

The first option is to hire an EPC contractor. This means they pay for the project from their pocket. They can save money. They take 100% of the risk. They are going to take a risk on execution. They are going to take risk on operation. In a new market, an entity that is cash-constrained will have trouble with that option.

The second option is to borrow money from a bank. Maybe they can get some concessionary loans. We see those coming into the market in places like Kenya. In that scenario, the customer still has a full obligation to repay the bank, and so it is on the hook.

In the third scenario, the one we are addressing, we, the developers, are taking on a lot of that risk: the execution, the operation, etc. In exchange, we need to pass on some of the regulatory risk, some of the change-in-law risk. The customer should appreciate that it has zero dollars out of its pocket on day one. In exchange for that, it must take a little bit of regulatory risk. That is a balance that not everyone will accept, but market to market, we see that around 30% to 50% of companies that want to go solar are willing to take on some of those long-term commitment risks.

MR. TILLEARD: Let me add a “scenario zero” that is to keep doing what you are doing: diesel and grid. Do you think these things are going to be the same 25 years on from now? Absolutely not. Making a sale requires convincing the customer that scenario zero is not an equivalent thing. You / continued page 30

The IRS said making plastics and similar petroleum derivatives is not a qualifying activity. At least two chemical companies are using MLPs to own facilities that convert ethane and propane into olefins that are used to make plastics after receiving private rulings from the IRS in 2012 and 2013 that such businesses qualify. The regulations allow them to continue. The regulations do not differentiate between olefins made from natural gas and crude oil. However, methanol is not on the EIA list of refinery products, so it is not a qualified product.

Services to minerals and natural resources businesses qualify only if they pass three tests.

The services must be specialized, essential and significant to the direct activity being undertaken by the minerals or natural resources company. The IRS said the tests are intended to “differentiate between mere provision of general services, goods, or equipment to others and active support” of a qualifying activity.

Services are “specialized” if the workers who perform them require special training unique to minerals or natural resources industries. If the company is providing property, then the property must be of limited use outside the direct activity and not be easily converted to another use. An MLP can provide injectants, like water or lubricants, for use in fracturing, provided it collects the injectants after use and cleans, recycles or otherwise disposes of them as required by law.

Services are “essential” if they are necessary physically to complete the direct activity or to comply with federal, state or local law regulating the direct activity. An example is water delivery and disposal to a gas fracturing site. Legal, financial, consulting, insurance and similar services are not considered essential.

To be considered “significant,” the services must require partnership employees to be an “ongoing or frequent presence at the site” and the employees must be doing something that is necessary for the direct activity. The IRS said the work can also be offsite provided the services are offered exclusively to / continued page 31

Corporate PPAs

continued from page 29

cannot completely de-risk solar versus the grid, but the grid is not de-risked either.

MR. GREEN: The other thing to bear in mind is that, in many cases, you are not dealing with a single person within a customer. You are dealing with operations, with a finance person, with senior management and, ultimately, with the board.

If you manage to convince three out of the four, that is not enough. You need all four. All these offtaker questions we have been talking about — essentially, “Why should I take on this risk?” — they generally go to the board. The board will say, “We buy currently from the grid. We have quality issues, and we may have future pricing issues, but we do not have any long-term commitments. So why should we jeopardize ourselves?” The type of arguments that Jeremy and Matt just made have to make their way to the senior management level, even though the operations and finance people see the merits of the project.

MR. NORMAN: Raoul Ilahbaks, I want to bring you in now because one of the things I initially thought we would address during this panel discussion is how to unlock capital for the C&I segment.

You and I discussed this previously. Interestingly, you do not think that there is a lack of capital in the market. You think that it may even be slightly too crowded.

Please comment on that. Secondly, maybe you can tell us what you think is needed for the C&I market truly to take off.

MR. ILAHIBAKS: Two perspectives. On the equity side, I think there is too much capital trying to find a home. I do not think there are any constraints in terms of equity financing.

If you look at debt financing, there are basically two options for smaller projects. Either you go to DFIs, who are willing to look at a portfolio approach. They want to see a pipeline of projects and will give a long-term commitment for a certain amount. In some countries in southern Africa, we have seen a number of DFIs give a US\$20 to US\$30 million commitment for a portfolio. But DFIs will generally not touch a single project or even several small-scale projects. There is not enough scale.

With smaller projects, the offtakers can go to local banks. But local banks do not typically have the required expertise, and this is a fundamental issue. The offtaker may then look for corporate-level debt. However, this can be burdensome for the offtaker and will eat into its ability to raise debt finance for its core business. Debt financing for projects in Africa really is a fundamental issue to address.

Regarding the length of the offtake agreement, I see things slightly differently than some of the other panelists. The contract term is a major challenge. In Africa, people really do not think on a 15- to 20-year horizon. This has implications in terms of raising adequate financing. ☹

Growth Area: Regasification and LNG-to-Power Projects

by Brian Greene, in Washington

The LNG market is shifting from a focus on liquefaction to regasification terminals in countries that are potential importers of LNG. Activity is increasing.

How will these projects be structured and financed? What are the main risks? We decided to take a closer look.

Market Shift

The US LNG liquefaction industry has had a remarkable rise in the span of just a few years.

The industry was essentially non-existent as recently as 2009 when only the Kenai LNG project in Alaska, with a capacity of 1.5 million tons per annum, was in operation, and there were no other announced liquefaction projects in development.

By January 2016, five projects totaling 62 million tons per annum of nominal capacity were under construction and more than another 30 announced projects were awaiting final investment decisions amounting to another 320 million tons per annum of nominal capacity.

One month later, the first commissioning cargo of US LNG departed from the Cheniere Sabine Pass export terminal to a crowd of cheering workers, Cheniere executives and government officials.

That the first cargo was departing on a ship named Asia Vision seemed appropriate given that the US LNG liquefaction industry's rapid growth had come about in large part based on the strength of long term contracts signed with global and Asia-based offtakers eager to exploit differentials between LNG prices in Asia that were between five and six times those at Henry Hub in Louisiana. Yet the Asia Vision was destined not for Korea or Japan but for Brazil — its maiden voyage perhaps a more potent

symbol of the rapid, evolving and global nature of the LNG trade rather than an ode to the US LNG export industry's beginnings.

Between 2013 and 2016, the price of natural gas decreased both domestically (from \$3.64 an mmBtu at Henry Hub in November 2013 to \$2.59 an mmBtu in June 2016) and internationally (from \$15.40 an mmBtu for landed LNG in Tokyo in November 2013 to \$4.55 an mmBtu in June 2016). At the same time, global nominal liquefaction capacity, which had already increased from 254.4 million tons per annum at the end of 2009 to 301.5 million tons per annum at the end of 2015, was projected in early 2016 to rise an additional 44% by 2021 to 433.55 million tons per annum, with about half of the increase coming from US liquefaction facilities under construction.

As a result, the market for new long-term offtake contracts has shifted in the buyer's favor, and development of additional liquefaction projects has slowed.

The buyer's market is now causing attention to shift to regasification and LNG-to-power projects in a number of countries, many of which are new to the global LNG trade and with limited or no existing capacity to import LNG. A year ago, only 33 countries imported LNG. By 2025, this number is projected to grow to more than 50, with the new importers increasing global demand by a projected 150 million tons per annum.

Ownership and Financing Structures

A regasification facility is a land based or offshore terminal — referred to as a “floating storage regasification unit” or “FSRU” — that regasifies LNG brought in by tanker.

A regasification facility owner earns its revenues either by purchasing the LNG and selling gas, or by selling capacity to terminal users. An integrated LNG-to-power project refers to a project that both regasifies LNG and produces power to sell to an offtaker or on the spot market.

The threshold structuring consideration is then whether it is possible for a regasification facility to be financed as a stand-alone entity based on its gas or tolling revenues, or if a regasification facility is only financeable together with an associated power plant as an integrated LNG-to-power project.

Generally speaking, the likelihood of a regasification facility being financed separately turns on the strength of the downstream market for natural gas in the receiving country and the appetite of project lenders to take project-on-project risk. Thus, regasification facilities in new importing countries are much more likely to be financed as integrated LNG-to-power projects either with the power plant being an / *continued page 32*

companies engaged in qualifying activities. An example is offsite monitoring. The employees can work for affiliates or subcontractors as long as they are being compensated by the MLP.

Renewable energy companies have been lobbying Congress since 2004 for the ability to operate as MLPs. They are not able to do so currently, mainly because their income does not come from “minerals or natural resources.” Energy sources like the sun or wind are not natural resources because they are inexhaustible. The phrase refers only to things that deplete.

A company that produces geothermal steam or fluid can operate as an MLP, but owning a power plant would take the MLP too far downstream from a pure minerals or natural resources business.

The new regulations apply to income earned on or after January 19, 2017. Most companies already operating as MLPs will have 10 years through January 19, 2027 to adjust to the new rules. This transition relief will be given to any existing MLP that, before May 6, 2015, had a private letter ruling, treating as a qualifying activity, an activity that the IRS regulations now treat as ineligible or that was treating an activity as qualifying under a reasonable interpretation of the US tax code. Merely having a “reasonable basis” for a position is not good enough.

The IRS said the fact that a partnership terminates for tax purposes during the 10 years will not cut the transition period short. A partnership terminates for tax purposes if there is a transfer of 50% or more of the profits and capital interests in the partnership within a 12-month period.

CALIFORNIA lost again in its effort to collect franchise taxes from passive investors in limited liability companies doing business in the state.

The state may have to pay millions of dollars in refunds.

California collects a minimum tax of \$800 from members in LLCs doing business in the state. The Franchise Tax / *continued page 33*

LNG-to-Power

continued from page 31

anchor tenant or the regasification facility being dedicated entirely to the power plant.

There are three likely financing structures.

In the most basic structure, the power plant and the regasification terminal are owned by the same entity and financed by the same lenders as a true integrated LNG-to-power project. This is the least flexible structure, and would be most likely to be employed for a smaller project where the regasification facility is not expected to provide gas to any other customers.

An alternative structure involves separate special-purpose vehicles owning the regasification facilities and the power plant, with both projects being financed jointly by common lenders. From the lenders' perspectives, this arrangement is an integrated LNG-to-power project, but the regasification owner and the power project owner will enter into an arms-length tolling arrangement or gas sales agreement. Variations on this structure could involve both special-purpose vehicles being jointly and severally liable for the loans, use of a holding company to borrow one tier above the two special-purpose vehicles, or an on-lending arrangement. This structure is more likely to be employed where the regasification facility has additional capacity for future customers, but a downstream market does not currently exist. Lenders to such a project are likely to require that the majority ownership and control of the regasification facility owner and the power plant owner are the same. However, in the future, the two legs of such a project could be refinanced separately and ownership split if the downstream market develops.

Finally, the regasification facility and the power plant may be owned and financed separately. Separate financings are more likely in countries with developed gas markets where the regasification owner has multiple potential customers.

In this structure, the equity ownership and control of the regasification facility and the power plant do not necessarily

need to be the same. Lenders to such projects will need to evaluate complex project-on-project risks. Regasification lenders will need to carefully analyze the project schedule for the power plant and the liquidated damages if the power plant does not achieve commercial operations by its guaranteed date. They will also need to consider the market for additional potential regasification customers and to negotiate adequate intercreditor protections to assure that the power plant is required to continue to fulfill its obligations in the event of a foreclosure by the regasification lenders. Lenders to the power plant will need to perform a similar analysis of the construction schedule for the regasification project and potential liquidated damages and to negotiate reciprocal intercreditor protections. The power plant lenders will also need to analyze the ability of the power plant to buy gas from another source or use another fuel (for example, diesel) for operations if the regasification project is not completed on time.

FSRUs v. Land-Based Terminals

The developer of an LNG-to-power project must decide whether to employ a land-based terminal or an FSRU.

Land-based terminals are more permanent and can be built to allow for a much larger storage capacity. They also typically have lower ongoing operating costs. However, construction costs for land-based terminals are generally higher and the construction period is longer than for an FSRU.

FSRUs, on the other hand, may be constructed by converting existing LNG tankers in as few as 12 months or by building a new vessel, which typically requires a 24-to-36 month construction period. FSRUs allow for more rapid fuel switching, are more adaptable to onshore space constraints and may require fewer permits.

FSRUs are the fastest growing sector in the LNG world and are generally favored in new importing countries where there is not an existing gas market.

In 2015, Egypt, Jordan and Pakistan added FSRU-based import facilities, as did Colombia and Poland in 2016. Nevertheless, regasification projects in other countries, including the AES Colón

project in Panama and the Jorf Lasfar terminal project under development in Morocco will use land-based terminals. Terminals in Ghana and Croatia were originally projected to be land-based but have reportedly since switched to FSRUs.

Given the current demand for

Low LNG prices are creating demand for regasification terminals in importing countries.

FRSUs, FSRUs could potentially be financed separately from an associated power project even in a country with no downstream gas market, with the FSRU lenders relying in part on the ability to redeploy the FSRU if the power plant does not reach commercial operation.

Other Issues

Development of regasification and LNG-to-power projects is on the rise because of the amount of LNG that is available globally and competitive pricing.

However, regasification and LNG-to power projects offer new importing countries additional benefits, including the ability to add to electric generating capacity on an expedited basis, alleviate intermittency issues caused by wind and solar projects and address environmental concerns in countries that rely heavily on diesel fuel or coal. For countries such as South Africa and Panama, regasification projects are seen as a potential catalyst for development of domestic natural gas markets.

As a result, regasification projects often enjoy strong governmental support, but they are complicated projects, and other considerations may come into play for potential sponsors or lenders.

The existence or potential to develop a downstream gas market is one such consideration.

If a joint financing structure will be used, local counsel will have to weigh in on the appropriate tax structure and third-party access rights to terminal capacity and confirm that license conditions do not prevent cross-collateralization of assets.

Other issues also need to be analyzed, including fuel price risk, creditworthiness of counterparties, contractual terms and permitting and real estate rights. The difference between the typical oil and gas project and an integrated LNG-to-power project is the analysis becomes more complex given the larger number of counterparties and shared facilities. The regasification project and power plant may be built by different contractors, requiring analysis of finger-pointing risk. Force majeure provisions must be traced through gas supply agreements, terminal use agreements and power purchase agreements to analyze whether penalties could be incurred under power purchase agreements or terminal use agreements when gas supply is excused. For projects in developing countries, review of dollarization and foreign exchange rules are critical.

Regasification and integrated LNG-to-power projects that have properly allocated these risks have been successfully financed. They are likely to remain a growth area at least through the next couple years. ☉

IN OTHER NEWS

Board has been sending overdue tax notices to LLC members. The notices ask for as much as \$2,000 to \$3,000 once penalties and interest are added.

State franchise taxes must be paid by every corporation that is formed in California, qualified to do business there, or actually doing business in California.

“Doing business” is defined as “actively engaged in any transaction for the purpose of financial or pecuniary gain or profit.” Anyone holding an interest in an LLC that is a partnership for tax purposes is considered by the Franchise Tax Board to be doing business in California if the LLC is doing business in California. Partners are normally considered to do directly what the partnership does.

A state superior court judge in Fresno County ruled in November 2014 that holding a passive interest in an LLC is not doing business in the state.

A state court of appeals upheld the decision in January. The case is called *Swart Enterprises, Inc. v. California Franchise Tax Board*.

Swart, a corporation formed in Iowa, operates a 60-acre farm in Kansas that feeds cattle for beef sales. Swart invested \$50,000 in 2007 for a 0.2% interest in a fund, called Cypress Equipment Fund VII LLC, that leases equipment to lessees in California. Swart has no other ties to California.

The appeals court said that business activities undertaken by a partnership cannot be attributed to limited partners. Swart was equivalent to a limited partner. It had no ability to participate in the management and control of the fund. Because the business activities of the fund cannot be attributed to it, it was not doing business in California.

Another state tax agency, the State Board of Equalization, takes the position that a limited partner in a limited partnership is not doing business in California solely by reason of holding the partnership interest. The Franchise Tax Board used to follow the same / *continued page 35*

Trump and Africa

by Ikenna Emehele, in New York

US government programs to promote construction of new power projects in Africa face an uncertain future after the US elections. President Trump said little about Africa during the campaign. He suggested in his inaugural address that US arrangements with other countries will be judged in the future in terms of what benefits they bring to the United States. The best advice is to “wait and see.”

Power Africa?

Congress passed an Electrify Africa Act in 2016 that directs US government agencies to prioritize loans, grants and technical support for power generation and transmission projects in Sub-Saharan African countries. The Electrify Africa Act builds on a Power Africa initiative launched by the Obama administration in 2013 with the goal of doubling access to electricity across sub-Saharan Africa.

No one knows yet whether President Trump will continue with the existing policies toward Africa or attempt to change them.

However, at least three changes seem likely.

First, US agencies stopped financing coal-fired power plants during the Obama administration. The Trump Administration is much more likely to support financing of coal plants in Africa.

Second, there will be personnel changes. People who run the Africa-directed programs for the US government are generally driven by two motivations. There is a developmental goal: many people in Africa still lack electricity and basic housing, and there is a desire to help them. There is also a commercial goal, which is that it is good business to invest in the bottom billion people on the planet. It is possible for personnel changes to affect the priority given to one or the other of these goals.

Third, the Power Africa initiative was given a statutory basis last year as part of the Electrify Africa Act. While the future of the program under Trump is unclear, at a minimum, a myth attached to it is dead. There has been a myth that Power Africa is basically an ATM machine with unlimited funds funded by US taxpayers and if you have a project in Africa, you just stand in line and get as much money as you need. That was never what Power Africa was about.

The reality is that Power Africa is a US government initiative to provide 30,000 megawatts of new electricity generation in Africa and to provide electricity to 60 million new customers. President Obama was not the first US president to try to help.

President George W. Bush was also interested in Africa.

Power Africa focuses on two things. One is to pull together and organize existing US resources — no new money, just existing US resources — so that African projects can be funded in a cohesive fashion. There is a marketing element to it which is to come out with a comprehensive method to sell the opportunity in Africa to US investors. It is also a logistics tool. What delays African projects sometimes is not really lack of funds but the local bureaucracy. Projects take a long time to be approved. If you want to do a power project, you go to the ministry of energy for approvals, and then go to the ministry of finance also to get the project approved, and the approvals may not stop there. Power Africa essentially gives a red phone to developers. It says to US developers with stalled African projects, here is the phone number of US government official that you can call to help with the process.

The Power Africa initiative was essentially a pet project of the White House. It did not have a statutory basis. The concern among stakeholders that Power Africa would not survive a new administration led to codification in 2016 as part of the Electrify Africa Act. Thus, it will take another act of Congress to repeal it. The Electrify Africa Act passed with unanimous support, but there is a reason: no new appropriations were required to fund it.

Broader Challenges

Moving more broadly to the challenges ahead, Africa is facing three macro issues.

Currencies all across the continent are losing value. For example, in Nigeria, the naira (NGN) is currently trading at 315 NGN to the US dollar. That is the official rate, but usually you have to get it in the black market, and the naira is trading in the black market at 500 NGN to the dollar. In early 2016, the exchange rate was 199 NGN to the dollar. Ghana and South Africa are also experiencing depreciating currencies. This is a significant problem for investors in power projects who borrow in hard currency — for example, US dollars or euros — and who are ultimately selling electricity to customers who pay in local currencies.

Currency devaluations come in cycles. There was a cycle in the mid-1980s when African countries implemented structural adjustment programs that devalued their currencies. To stick with Nigeria, the naira-dollar exchange rate has been fairly consistent for the past five years before the most recent decline.

The market to hedge local currency risk in Africa is not well developed. A few banks, like Standard Bank, have limited products. To mitigate, sponsors could shift the currency risk to the host government since the government is better placed than a

developer to manage currency devaluation. Sponsors could also explore incorporating a local currency tranche to the extent equipment or services are sourced locally to match local currency revenues to the local payment obligation. In addition, limited currency risk could be passed on to the EPC contractor in return for a higher upfront payment. This works if the contractor will also operate the project and expects to have significant continuing local currency expenses.

Another macro issue is an inadequate transmission grid. More investments are expected in renewable energy, but the sites with good insolation or steady winds tend to be in remote areas, and a new transmission network is needed to move the power from the generating source to the high-density urban areas where the demand is. It is extremely challenging to finance construction of new transmission networks across the continent.

Currencies all across Africa are losing value.

Another fundamental issue is the weak balance sheets of the local utilities and host countries. Because of the decline in commodity prices, especially oil prices, and because of the devaluation in currencies, some African countries are in a recession and the balance sheets of the utilities are not as good as they were just a couple years ago. All deals require careful credit enhancement as a result.

Practical Advice

This is probably one of the best times ever to invest in Africa, but it is important to be cautious. Focus on a particular sector. Figure out the preferred technology. Understand that the opportunities and challenges differ from one country to the next. After picking the right country, find a good local partner who understands the market and can help share the risk.

Diversify your lender sources as much as you can. For instance, if you are doing a project and you have / continued page 36

approach, but changed its position in a ruling while the Swart case was pending in the superior court. Its current position is that each partner in a partnership — including an LLC treated as partnership — is considered to engage in whatever business the partnership does. The ruling is Legal Ruling 2014-01.

The appeals court said the Franchise Tax Board's position "defies a commonsense understanding of what it means to be 'doing business'."

US GENERATING CAPACITY stood at 1,183,740 megawatts at the start of 2017.

Coal continues to fall as a percentage of the total. Current coal capacity is 291,790 megawatts, or 24.65% of US generating capacity, according to figures released by the Federal Energy Regulatory Commission on February 1. Coal retirements in 2016 were approximately 8,900 megawatts, according to Platts Analytics. The utilities that own the 2,250-megawatt Navajo Generating Station in Arizona announced plans in February to close it.

Gas capacity accounts for 511,740 megawatts, or 42% of total US generating capacity. Another 8,689 megawatts of gas-fired power plants went into service in 2016.

Total US wind capacity is 81,870 megawatts, or 6.9% of the US total. Another 7,865 megawatts of new wind farms were built in 2016.

US solar capacity is 23,700 megawatts. Another 7,748 megawatts of new solar capacity was added in 2016, according to FERC. GTM Research and the Solar Energy Industries Association put the 2016 capacity additions at 14,635 megawatts.

Solar additions are expected to slow in 2017. The US Energy Information Administration expects another 5,700 megawatts, including rooftop installations. Platts Analytics has the figure at 2,500 megawatts. Platts is tracking 6,900 megawatts of new wind farms that it expects to come on line in 2017. It sees 12,900 megawatts of new gas-fired power plants either

/ continued page 37

Africa

continued from page 35

the option of getting US lending, European lending and local lending, seriously consider all three because each lender brought into the syndicate lets the project tap into different networks that can help if there are problems.

Where are the best opportunities?

One is LNG. There is an oversupply of LNG in the world today because of the historic low natural gas prices, but Africa has few intake facilities. There is an opportunity to build intake facilities that would take in LNG and store, re-gasify and supply it to local plants. For instance, South Africa recently announced a procurement for 3,000 megawatts of LNG-to-power.

Three different kinds of opportunities exist for investment in renewable energy. One is utility-scale projects that sell to the grid, another is inside-the-fence projects that sell directly to mines or factories with high demand, and another is smaller distribution generation like micro-grids or rooftop solar. Interest in distributed generation is exploding in Africa. There is a real competition today to sign up solar customers. [For more information about the emerging business models in the rooftop solar sector, see “Off the Grid in Africa” starting on page 36 of this issue.]

There are also opportunities to finance projects. Just as in the developed countries, there is a serious shortage of financing for early-stage development.

Many Africans are worried about the potential impact of the Trump administration. The best advice is to wait and see. While the near-term future of US support for development in the power sector is unpredictable, Republicans, like President Bush, provided massive funding for HIV and AIDS work in Africa, so interest in Africa can cross party lines. ☉

Off the Grid in Africa

by Rachel Rosenfeld, in Washington

Several new business models are helping off-grid energy projects get traction in sub-Saharan Africa.

The most prevalent models for such projects are stand-alone systems and micro-grids, where consumers can pay for energy in installments or as needed using their mobile phones or scratch cards.

More than \$223 million in investments was committed to off-grid solar companies and projects this past year, particularly for pay-as-you-go models, which are leading new investments and are increasingly viewed as a new category of infrastructure investment. In comparison, \$158 million was raised the previous year. These investments, consisting of commitments by private equity funds and individual equity rounds, are breaking the previous trend of relying on impact investors and donor capital.

US government agencies and international development finance institutions are also playing a large part by providing equity, debt, insurance, loan guarantees and other resources.

The need for off-grid projects in the region is clear: sub-Saharan Africa is the only region in the world where the number of people living without electricity is increasing, and more people in sub-Saharan Africa currently live without access to electricity than any other region in the world.

Nearly 80% of those lacking access to electricity are in rural areas. Off-grid projects are perfect for such an environment. Building out transmission would be too costly and time-consuming.

The International Energy Agency forecasts that off-grid development will increase dramatically in the coming decades. By 2040, 315 million people in rural areas are expected to gain access to electricity; approximately 80 million of these will do so through off-grid systems and 140 million through micro-grids.

Business Models

Small photovoltaic systems currently are still too expensive for the broad mass of people in developing countries.

Several business models are helping to overcome this hurdle.

One is a fee-for-use model, not unlike the solar leases that have helped the sector get traction in the United States.

Under this model, the customer does not buy the stand-alone system, but only pays rent to use it. A solar company retains ownership, ensures that the system is operating properly and is responsible for maintenance. The customer makes a one-time installation payment as well as reoccurring fixed payments based on the size of the system.

The other model is a pay-go model that is an installment sale. The difference between the two models is the customer under the pay-go model ends up owning the system after a period of time, usually six months to three years. Some solar companies offer additional appliances that can be purchased in cash or financed over a few years' time and can use the initial system as collateral once it is purchased. The solar company may provide

maintenance services until the customer fully pays for the system or, in some scenarios, the customer is responsible for maintenance from the start.

Under both models, the system is blocked automatically if the reoccurring fee is not paid and cannot be used again until credit has been restored. The reoccurring fee is usually paid using mobile phone payment services. In some instances, scratch cards are used, where the cards are purchased locally and contain a code to unlock the system for a certain period of time.

In either model, the solar company can play all three roles of system owner, operator and maintenance provider and bill collector, or the roles can be split and a separate company brought in to handle customer collections.

In a variation on these models, at least one solar company rapidly getting traction in the region acts merely as an equipment vendor providing financing. It designs, manufactures, distributes and finances off-grid solar systems and has 36 retail locations in two African countries and expects to extend to 400 retail shops in the next two years.

The common theme in all the models is the use of automated cashless payment processes through agent networks and remote or cloud-based monitoring that together provide significant leverage over the customer.

As these models increase in popularity, the solar installers may amass large portfolios of loans that may need to be refinanced.

Most of the loans are denominated in local currency, while the capital that finances the solar company may be denominated in US dollars or euros. Therefore, the emerging business models carry currency exchange risks where, if the local currency is devalued, an additional cost will be imposed that is unrelated to business and operations.

Micro-grids are another emerging business model.

Micro-grids are small utilities. The solar company installs an array, perhaps as small as, or even smaller than, 100 kilowatts, and it is used to supply service to a small village in a remote area. As in the other models, the solar company can retain ownership and operate and maintain the equipment as well as collect fees for services from customers or the roles can be split among separate entities. In some instances, installation and maintenance are provided by rural energy cooperatives owned by local residents.

Any rural development requires collaboration with local governments and utilities, as well as a thorough understanding of local legal structures.

/ continued page 38

under construction or in late-stage development.

All of this is occurring in a market in which electricity demand is flat. US electricity demand fell in 2016 for the second straight year, according to the Energy Information Administration. EIA reported average daily demand of 10.69 trillion MWhs a day in 2014, 10.68 in 2015 and 10.58 in 2016.

Electricity prices set record lows in 2016. The PJM western hub, which is the most actively traded US power location, saw spot prices average \$28.78 a MWh in 2016, a 19% drop. Spot prices in ERCOT averaged \$24.65 a MWh in 2016, the lowest level on record.

MINOR MEMOS. Solar electricity is expected to be the cheapest generating source by the middle of the next decade. The winning bids in auctions to procure solar projects were US2.91¢ a KWh in Chile in August and US2.42¢ in September in Abu Dhabi. Expectations are that lower prices will be bid into new tenders this year in Saudi Arabia, Jordan and Mexico The average one-megawatt solar system costs US\$1.14 a watt to build today. Analysts at Bloomberg New Energy Finance expect the average cost to fall to US70¢ by 2025 The Southwest Power Pool is the first regional grid in the United States to serve more than half its load from wind electricity. It reached 52.1% wind at 4:30 a.m. on February 12. The SPP serves 14 states in the central US from North Dakota south to Texas.

— contributed by Keith Martin in Washington

Africa

continued from page 37

Recent projects involving micro-grids have included a solar array, batteries and often a diesel generator for back-up generation and sometimes have incorporated wind. Some models allow subscribers to prepay for power based on their needs, while others charge a set reoccurring fee.

Micro-grid solar farms may be deployed through turnkey implementation or various actors. In Tanzania, one company will send a shipping container that has in it a ready-to-assemble solar array of up to 100 kilowatts of installed capacity, including modules, cabling, inverters, foundations, and monitoring and installation tools. The arrays are assembled onsite and offer power to residents in remote regions on a rental basis. They can be installed in six days and deployed individually or in multiple arrays. The arrays are configured for low-voltage power so they can connect directly to existing networks and either hybridize with or displace diesel generators. A local business can rent one or more of the arrays from the company, paying an initial installation fee and then further fees based on energy used, as monitored by the company. The local business can effectively sell part of the electricity by renting individual solar panels to other businesses or residents.

Two 100-kilowatt arrays were built and rented to a local mini-utility using the capital from a convertible loan, and the mini-utility will construct a micro-grid and connect and bill customers. If this project is successful, then up to 30 additional ready-to-assemble grids may be installed across the country.

US Government Help

Solar companies using the fee-for-service and pay-go models receive support from various government and multilateral lending agency programs, such as the Electrify Africa Act, the Power Africa Initiative and World Bank Group and other development finance institution initiatives.

The Electrify Africa Act is a US statute under which the US government has put together an interagency working group to assist US government agencies to prioritize loans, grants and technical support to leverage private-sector capital for power generation and transmission projects in sub-Saharan African countries. The related Power Africa program is supported by 12 US government agencies and a myriad of private sector partners.

The US agencies are starting to put serious money into the program.

For example, the Millennium Challenge Corporation now has five ongoing power-focused compacts or threshold programs in sub-Saharan Africa through which \$680 million has been spent in just the past year. Of that amount, \$46 million was for off-grid electrification in Benin, MCC's largest off-grid electrification effort to date.

The Overseas Private Investment Corporation made a \$15 million loan to Lumos Inc. to sell home solar kits in Nigeria, a \$5 million loan to Greenlight Planet Inc. to expand its distribution of solar energy products to underserved populations in sub-Saharan Africa and a \$15 million loan to a new investment vehicle managed by SunFunder Inc. that will provide financing to companies operating in developing countries that manufacture, distribute and install solar lighting and energy systems.

The US Agency for International Development has provided risk coverage for approximately \$143 million in loans to power projects, including a \$75 million pan-African facility for loans to off-grid producers, manufacturers and distributors across sub-Saharan Africa.

The US Trade and Development Agency partnered with Renewable World East Africa to develop micro-grid solar and battery storage systems in Kenya this past year and, more recently, launched a tender for clean energy projects in sub-Saharan Africa with proposals to be submitted in February 2017.

The US African Development Foundation, which supports an effort called the "Off-Grid Energy Challenge" in partnership with USAID and General Electric Africa, has made 50 grants of \$100,000 each to entrepreneurs and private organizations developing innovative off-grid technologies and an additional 21 grants are in the works.

USAID has also developed a "Power Africa tracking tool," an online and mobile application that allows users to track power sector development, transactions and projects -- a useful resource for developers and lenders interested in the off-grid sector. Users can view transaction status by project in each country, statistics on generating capacity, energy mix and available technology, and active projects, and also read the latest news on the African energy sector. The tracking tool also tracks the environmental, social and other impacts of these projects.

DFI Engagement

Development finance institutions have been involved in about 25% of the investment rounds of off-grid solar ventures. This involvement has been in the form of grants, equity, debt and loan guarantees.

The World Bank launched a "Scaling Solar program" recently

in Zambia. The program was a utility-scale solar PV competitive procurement process designed to make it easier for Zambia to procure solar power quickly and at low cost through competitive tendering and pre-set financing, insurance products and risk products. Two provisional winning bids were selected at US6.02¢ and US7.84¢ per kWh, which represent some of the lowest solar PV costs to date in Africa and among the lowest in the world. Because the US6¢ Zambian tariff is fixed for 25 years and will not rise with inflation, it represents about US4.7¢ per kWh over the life of the project, which is on par with recent auctions in Peru and Mexico.

Neoen/First Solar and Enel are the winning bidders, and they are expected to reach financial close on the projects within three months and complete construction on the two sites (up to 50 megawatts each) a year later.

Several new business models are helping distributed generators get traction in Africa.

The Scaling Solar program plans to develop 1,000 megawatts of solar power in the next three years. Zambia has committed to a second round of tendering, and Senegal and Madagascar have also enrolled in the Scaling Solar program.

In addition to the Scaling Solar program, the International Finance Corporation, a member of the World Bank Group, has developed a “Lighting Global program” as a platform to support growth of the off-grid solar market. Participants in the program receive IFC’s advice on how to verify the quality of products, market them and expand their reach on the basis of sales trends. IFC and FMO, the Dutch development bank, invested approximately €14.6 million in equity in Mobisol GmbH, a Berlin-based company and an associate of the Lighting Global program. Mobisol uses a pay-go business model for modular solar systems.

The IFC also recently launched an “Off-Grid Market Opportunity Tool,” an online tool that draws on a database to help users assess the potential market for off-grid energy

solutions. The database platform builds on open geospatial data to let users see where there is a need for off-grid electrification. The open-source software also allows users to improve its functions by building on the code. Users can also export analyses generated by the platform and combine them with other data. Unlike the US government data tool, this tool does not show current projects; rather, it tracks population, solar power potential and electrification paths.

Private Sector

More than 100 private companies have pledged to develop nearly 16,000 megawatts of electric generating capacity as part of the Power Africa initiative. This represents more than \$40 billion in commitments. More than 40 of the companies are focused primarily on micro-grid and distributed generation in sub-Saharan Africa.

There have also been notable recent investments from Africa-focused private equity funds in pay-go solar home system companies.

In South Africa, Enel Green Power is now offering Tesla home power kits to customers. While no funding options are available to purchasers of the home power kits, Enel’s view is that the forecasted increases in South Africa’s electricity prices are enough to induce customers to pay the large initial upfront costs. Tesla anticipates significant

growth on the continent and plans to use South Africa as its springboard to the market.

Private-sector lending is also on the rise. Off Grid Electric, a private company, recently announced that it raised a record \$45 million in financing in a single debt round for solar power and battery storage, bringing its total capital raised to \$70 million over the past year, including a \$25 million series C investment led by various private sector lenders.

Some companies are packaging customer contracts from off-grid solar installations in Africa and securitizing the payment streams. BBOX recently held a \$20 million series C funding round led by Engie (formerly GDF Suez). BBOX previously led the first-ever securitization of off-grid assets about one year ago for \$15 million. BBOX’s asset-backed notes, called distributed energy asset receivables, represent a bundle of customer contracts based on monthly installments. BBOX aims to raise up to \$5 billion over the next five years. ☉

2017 Market Trends

More than 250 people gathered in New Orleans at the annual Infocast projects and money conference in January to hear what the year ahead might hold in terms of deal flow. A panel of three investment bankers and an industry consultant spoke on the opening panel about whether the possibility of corporate tax reform is already affecting deal flow, the wall of private money, particularly from Asia, looking to invest in US assets, current discount rates used to bid, the potential for energy storage to displace gas-fired power plants, what the panelists are putting on their own business plans this year as potential areas for growth, and other topics.

The panelists are Andy Redinger, managing director and group head, utilities and alternative energy, KeyBanc Capital Markets, Ted Brandt, CEO of Marathon Capital, Jonathan Cody, managing director at Whitehall & Company, and Shanthi Muthiah, vice president and power sector lead at consultancy ICF International. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We start 2017 with probably greater unpredictability than any year I can remember. The Republican sweep in the elections makes corporate tax reform more likely. Is the threat of tax law change already playing out in deals and, if so, how?

Tax Uncertainty

MR. REDINGER: It is early. People are still feeling their way.

MR. MARTIN: Ted Brandt, you put out a paper about the potential effects of tax law change. The wind sector was the main focus. How do you see this playing out in deals?

MR. BRANDT: It was really solar and wind, but our conclusion was that the expected corporate tax rate reduction will not affect solar very much. It will affect wind largely because wind is more tax intensive. It will play out pretty significantly. Sponsors will have to put up more equity. There will be new structures where risk sharing that has not been part of the calculus will have to occur. It will add friction to the market.

One of our conclusions was that the uncertainty about tax reform favors people with balance sheets and with lots of capital, and that could fuel M&A by small and medium-size developers to grow larger.

MR. MARTIN: You thought that there would be more M&A in the wind market, but hasn't that sector already consolidated? What is left to consolidate?

MR. BRANDT: There are a few.

MR. MARTIN: Why not also in solar?

MR. BRANDT: Our analysis is the tax credits are not going to go away. What will happen is the tax deferral from accelerated depreciation will decline in value due to the tax rate reduction.

The offset is that you are paying less taxes once you are on the other side of the flip. The present value of that pickup more than offsets the loss in deferrals for solar projects. Unfortunately, that does not happen for wind.

MS. MUTHIAH: Obviously a lot of focus is on how this will affect the renewable sector, but we continue to see M&A activity on the conventional side, and we do not expect any slowdown in that sector while Congress is debating how to rewrite the tax code. So far we have not seen any direct effect on M&A pricing or even in the pricing of independent power company stocks and valuations.

MR. MARTIN: You anticipated my next question, which is whether the financing and M&A markets will function normally this year while Congress is debating major tax reform.

MR. REDINGER: I think there will be an increase in M&A activity. There is a way to structure around the tax risks. The potential for future changes in tax laws may cause people to act. The big unknowns are where the corporate tax rate will land and what sort of cost recovery, if any, will be allowed on imported equipment.

MR. MARTIN: Is there an inconsistency in saying you expect an active M&A market and there are two big unknowns?

MR. REDINGER: A market will remain for seasoned projects that have already been financed and maybe are at or through their tax equity periods. Operating projects will be more valuable. Tax reform is largely an upside for them.

MR. MARTIN: Operating assets will be more valuable because the lower corporate tax rate will mean the after-tax cash flow from operating them will be higher. Yet the buyer does not know what sort of cost recovery he will get. How does he bid?

MR. REDINGER: Maybe you include an earn out. There are ways to structure around uncertainty. The sheer amount of capital chasing this asset class is still immense. Given the number of potential investors and the amount of capital chasing, you will find people willing to structure around that risk.

MR. MARTIN: Ted Brandt, do you agree?

MR. BRANDT: Yes. The wild card is the House Republican tax plan has full expensing for capital spending, and it eliminates interest deductions. These proposals will affect what ultimately happens in M&A. We could also see a shift from partnerships to

corporations that will be taxed at a lower marginal rate. Less leverage due to loss of interest deductions could give strategic investors an advantage over financial investors.

MR. MARTIN: Do you agree with Andy Redinger that the market will continue to function normally in the face of the uncertainty this year?

MR. BRANDT: I agree that there is so much capital trying to get deployed in American assets that creative people will figure it out.

MS. MUTHIAH: I agree with that to a point. M&A activity could start strong, then the market could be thrown into limbo as the tax law changes come into clearer focus, and there could be a period of wholesale repricing.

MR. MARTIN: Ted Brandt, you often represent sellers. In some deals currently in the market, people are adding “schmuck insurance.” No one buying assets wants to feel like a schmuck for having overpaid when the law changes, so there is a one-time price reset after any tax overhaul bill clears Congress. Do you think this will be attractive to sellers? They would take the risk of tax law change.

MR. BRANDT: We shall see. I am in the middle of a whole bunch of schmuck insurance conversations.

Potential Consequences

MR. MARTIN: The House tax reform plan has been thrown into disarray. It would reduce the corporate tax rate to 20%. Trump wants to go to 15%. It would deny interest deductions. It would allow immediate write-offs for new equipment, but no cost recovery at all for imported equipment.

Starting with the interest deductions, do you see companies rushing to put in place construction or corporate revolvers so that the debt will be grandfathered from the loss of interest deductions? Presumably interest will remain deductible on existing debt when the tax laws change.

MR. BRANDT: We are not seeing that yet, but I can see your point.

MR. MARTIN: How do you expect the denial of cost recovery for imported goods and services to affect the market? Are you seeing any change in behavior in anticipation of this potential tax law change?

MR. BRANDT: It would sure affect solar. I think you have one or two companies that manufacture solar panels here, so it would have a huge effect. Wind should not be affected as heavily as more and more wind equipment is manufactured domestically. I think gas turbines by and large are made in the United States.

MR. CODY: Isn't this the equivalent of an import duty? Wouldn't it violate the GATT treaty to which the US is a party and end up before the WTO? There is a lot of chatter about the so-called border adjustment. The volume is probably louder inside the Beltway than outside.

I think the market functions normally until the tax reforms come more clearly into view. We are seeing people take proactive measures on the tax equity side. The tax equity investors are looking for indemnities. That obviously affects what sort of sponsors will be able to conclude deals. They need to be credit-worthy enough to stand behind indemnities.

MR. MARTIN: What should a developer do when bidding into a power contract solicitation? The developer has to make some assumption about his or her cost of capital.

MR. BRANDT: What we are hearing from the very largest guys is that they are trying to pass this off to the utilities in their power purchase agreements, but so far they are being straight armed. The risk obviously has to be borne by someone. It will probably end up being borne by the cash equity investor. The dollar amounts could be large.

I do not know whether anyone in this room has looked at what deficit restoration obligations for tax equity investors will look like if you have full expensing and no interest deduction. They go through the roof and could exceed the original investment. No tax equity investor will step up to such an obligation.

MR. MARTIN: Let's break that down. Many renewable energy companies raise tax equity through partnership flips. It is impossible to transfer all the tax benefits to the tax equity investor in such a structure unless the investor agrees to invest additional money when the partnership liquidates in the amount of any negative capital account. Each partner has a capital account. Capital accounts are a way of tracking what each partner put in and took out. A partner with a negative capital account took out more than his fair share. Tax equity investors in these structures do not start with a high enough capital account to absorb all tax benefits. You are saying that tax reform will make the problem worse. Tax equity investors will have to agree to even larger deficit restoration obligations than they do today.

MR. BRANDT: Correct.

MR. MARTIN: Won't investors simply stick to the level of DROs with which they feel comfortable today? The end result may be tax equity will be a smaller share of the capital stack for the typical wind or solar project.

MR. BRANDT: Time will tell.

MR. MARTIN: Returning to the border / continued page 42

Market Trends

continued from page 41

adjustment, or the idea that no cost recovery will be allowed on imported equipment. This part of the House Republican tax plan would raise \$1.2 trillion. It would shift \$1.2 trillion in tax burden over the next 10 years from one group of companies to another. Trump told *The Wall Street Journal* two days ago that he is not a big fan. He thinks it is too complicated. He prefers import tariffs.

If the border adjustment falls away, then who knows where the House Republican plan is left. Advocates of the border adjustment say it is no big deal for importers because the dollar will appreciate so much that imported equipment will cost less in dollar terms. The \$1.2 trillion will be a wash.

What effect, if any, will a stronger dollar have on our market?

MR. BRANDT: It is not a single variable analysis. We are seeing an influx of global capital into the United States wanting to invest in dollar-based assets with the expectation that the dollar will strengthen. The amount of inbound US investment is potentially enormous.

MR. MARTIN: From where is the money coming?

MR. BRANDT: Surprisingly, we are seeing a lot from Europe, but most of it is from Asia. There is also an incredible amount of money coming down from Canada.

MS. MUTHIAH: Asian investors have been focused on this market for some time, with the Japanese leading the pack and the Koreans on the fringes. We are starting to see greater interest from China.

If you look just at PJM combined-cycle development as an example and at what is in the pipeline today, 15% to 20% of it has some share of foreign ownership. The vast majority is Asian ownership. The European focus has been more on the renewables side. The US has been an attractive market, and we see it remaining so.

MR. MARTIN: The European focus has been on the renewables side. The Asian focus has been on gas, renewables, what?

MS. MUTHIAH: Japanese investors have been focused largely on gas in general and combined-cycle gas-fired power plants in particular. The burgeoning Chinese interest has been in the renewable energy sector.

MR. MARTIN: What is bringing these people in? Is it the anticipation of a stronger dollar or something else?

MS. MUTHIAH: It has been more limited opportunities in Asia versus better opportunities here. It is not a post-Trump phenomenon.

MR. BRANDT: I think your 15% to 20% estimate is low. I think the figure is closer to 50% Asian participation in new builds.

MS. MUTHIAH: Going forward, the figure is clearly increasing.

MR. CODY: Another factor is the risk-adjusted yields are better in US projects.

Wall of Money

MR. MARTIN: Jon Cody, you and Andy Redinger were on a panel last summer on which the participants said a “wall of private money” is coming into the US market. Would you say that remains true? Is the amount increasing?

MR. CODY: It seems to be. There is an unending amount of it. This is never ending. It has staying power. I am not seeing any change whatsoever.

MR. REDINGER: If anything, it is picking up. We have seen Korean investors become much more active in the last 12 to 18 months, and we think that trend will continue. The Koreans will probably make the transition from being senior lenders to putting in more equity.

MR. MARTIN: Yesterday we heard on a cost of capital webinar that the interest rates are falling in both the bank and term loan B markets, but tax equity yields have remained flat. In which direction do you think equity returns are moving: up or down? If there is a wall of private money, should they be increasing?

MR. CODY: It has been a roller coaster ride. Honestly, we are seeing equity returns recover a bit. The yield co blow up hurt them. The wall of private money helps developers because it bids up valuations for their projects.

It depends on the market segment. We have not seen much movement in quasi-merchant projects with hedges. However, when you look in PJM, for example, at any gas-fired assets with a 15- or 20-year PPA, the return requirements are stunning.

MR. MARTIN: Give us some numbers.

MR. CODY: We are looking at equity returns in the mid-teens for a hedged merchant project.

MR. MARTIN: Pre-tax?

MR. CODY: Pre-tax. A lot of these folks, especially the Japanese, have very different tax positions based upon their activity in North America. So everyone is looking at pre-tax. We are seeing mid-single digit returns for a contracted peaker.

You can see where a solar project that has far fewer moving parts than a peaker could price at close to the offtaker's credit rating, but people are pricing even a relatively simple technology like a peaker through the floor. That is the effect of the wall of capital.

Storage Arbitrage

MR. MARTIN: Jon Cody, the previous speaker, William Nelson from Bloomberg, put up a number of slides. One of the interesting things was how prices in California for ancillary services and for electricity in the late afternoon and early evening when solar drops off the grid are spiking in order to give gas-fired power plants enough incentive to remain on line during the day time when they are getting crushed by inexpensive solar and running up big losses. The high prices during peak hours allow them to recover their losses and earn a small profit. Nelson said there is a golden opportunity for energy storage companies to steal that revenue.

That does not say much for the long-term viability of gas in California. What about in PJM?

MR. CODY: California is a market unto itself. Government policies and actions by the local utilities influence power prices in ways that prices may not move in other parts of the country.

MR. MARTIN: Will you see the same arbitrage opportunities for storage facilities to displace gas in the east?

MR. CODY: We do not see as much penetration by solar or storage in the east as we do in California and Texas.

MS. MUTHIAH: In California, it is not just the ancillary services market but also the capacity resource adequacy structure that is causing distress for gas.

MR. MARTIN: Shanthi Muthiah, this is an area of special expertise for you. When you watched William Nelson's presentation, did you say to yourself, "Storage companies are eventually going to eat the lunch of the gas-fired generators in California?" Do you see that also happening eventually in the east?

MS. MUTHIAH: The storage market is still in its early days and faces a number of challenges. Storage is coming down quickly in cost. We are talking about costs today in the range of \$1.4 to \$2 million a megawatt. They are still markedly higher than for competing generating assets. The regulators are also still wrestling with how best to compensate storage companies. The regulatory piece needs to be worked out on top of the costs coming down for storage to start to have a transformational effect on the market.

MR. MARTIN: So we are still a little far away from full-scale deployment of storage.

MS. MUTHIAH: Yes. There was some potential for it, but the prospects, at least on the regulatory side, have probably receded after the November election.

Discount Rates

MR. MARTIN: Ted Brandt, what are current discount rates for winning bids for wind and solar projects?

MR. BRANDT: People are still absorbing the news and watching Twitter every day. Fully-contracted solar is selling to a 30-year pro forma of about 7% after tax, unleveraged. Wind is about 8.5% to 9%. I don't think the wind number has changed for a couple years.

The difference is that buyers are now looking at the potential for greater tax deferral if the US government moves to full expensing of investments in equipment. This has not been factored yet into pricing. Any buyers have to rethink whether there are any other risks besides tax law change that should be shifted to sellers.

MR. MARTIN: The 7% discount rate is for utility-scale solar? What about rooftop solar?

MR. BRANDT: We have not seen much difference between well underwritten investment-grade rooftop and utility-scale solar. The discount rates have converged because of the wall of money. We did three distributed generation deals last year, and the rates were right in line with what I just described.

MR. MARTIN: Are buyers already taking into account the possibility of a lower corporate tax rate in their pricing? The out-year after-tax cash flows will be higher. You say no, Ted, because people price on a pre-tax basis. Does anyone disagree? Andy Redinger, you are shaking your head no.

MR. REDINGER: No.

MR. MARTIN: A lot of the solar assets changing hands are in California. One of the challenges in California is that a sale of an operating solar project will trigger a property tax reassessment. The cost could be substantial. How serious an impediment has this been in bids for California assets?

MR. REDINGER: The first owner after a solar project is first put in service gets a break on property taxes, but if the asset is sold later, the property taxes go to fair market value, which can hugely deteriorate value. What some people try to do is have two buyers. Each takes a 50% interest so that there is no change in control. A change in control triggers a reassessment. It has been a significant issue in every California solar asset with which we have dealt.

MR. MARTIN: One more question along these lines, and then let's move to a new topic. Some analysts are saying that PPA prices will have to rise because of the tax law changes in order for wind and to a lesser extent solar projects to remain economic. But we said on this panel that the corporate tax rate reduction will make operating assets more valuable. / continued page 44

Market Trends

continued from page 43

Is there an inconsistency in saying PPA prices have to rise to justify new builds, and yet these assets, once built, are ultimately more valuable?

MR. REDINGER: For new builds, the depreciation is potentially less valuable. Someone has to fill in the hole. Either the equity will have to accept a lower return or PPA prices have to rise.

MR. MARTIN: But the owner has a more valuable asset.

MR. REDINGER: True for a mature project, but to get the project built, someone has to fill in the hole in the capital structure.

If I am selling a mature project today, it is more valuable because there will be less in taxes. But for a new build, somebody has to fill that hole. You also have to remember, as Jon Cody said, most of the market thinks of the world as pre-tax because they think that they are going to do enough new deals to shelter the current taxes.

Debt Outlook

MR. MARTIN: The story so far is the M&A market will continue to function as it has. People will watch Capitol Hill, but they are not stopping in their tracks. They have not changed the pricing in anticipation of something happening on Capitol Hill, at least so far.

Let me shift gears. Debt markets. Where was most of the action in 2016 in the debt market, and do you expect the same in 2017 or are there some emerging new trends?

MR. CODY: The action for us has been mainly in solar. I suspect that will remain true this year.

MR. MARTIN: Andy Redinger?

MR. REDINGER: The biggest trend has been the very large tickets being bought by Asian banks in the syndicated loan market. We are talking about holds by Chinese lenders of \$125 million. We are seeing Koreans participate more or less as a consortium for \$200 to 300 million increments.

MR. MARTIN: Jon Cody, are the Asian banks lending longer tenors? Most of the US banks are at seven years.

MR. CODY: No. In the hedged merchant market, we see construction plus five years as the norm. We do not see any movement on that.

MR. MARTIN: Chinese lenders were rumored to be offering better terms than other banks. At the same time, the Chinese government has been discouraging Chinese companies from investing overseas because of the downward pressure on the Renminbi. How is that affecting Chinese lending?

MR. CODY: We have not seen it tail off. Obviously there has been a sea change in exports of equity capital out of China. However, it has not played out fully yet in the market.

MR. MARTIN: Most of the money coming in last year was looking to invest earlier in the development cycle, at the notice-to-proceed stage, for example. Are you still seeing that or is there a move to invest even earlier in the process?

MR. CODY: Nobody wants to get involved in the notice-to-proceed stage on purpose. They do it because they are not getting any business waiting around for projects that have reached the end of construction. By then, the movie is over, and the deal is gone. We are seeing lots and lots of companies willing to deal with late-stage development risk in the search for yield. Maybe there is a PPA, but there is still some permitting risk, transmission risk, some deposits that need to be put down. Companies that three years ago were purists refusing to take any construction risk are now coming in much earlier.

MR. MARTIN: Ted Brandt, you said at past conferences that there was little interest in buying development rights to projects, particularly where the developer does not yet have a PPA. Is that still the case?

MR. BRANDT: That changed pretty dramatically last year. The open question is how it will be this year. There were a number of wind developers who went long in turbines, but came up short on projects in which to deploy the turbines. They did not foresee that Congress would extend the tax credits at the end of 2015. So there was a big bid for development assets. The open question is what people will make of the outlook with a new administration in power.

MR. MARTIN: It seemed like last year the pipelines had thinned.

MR. BRANDT: By late 2015, nobody was developing post-2016 projects.

MR. MARTIN: Then you saw at conferences in early 2016 CEOs were showing up for the first time in years trying to decide whether to dive back into the development game. Did they dive back in? Have development pipelines been restored?

MR. BRANDT: There were a few new entrants. For example, Tenaska bought a small portfolio and is in the development business. Longtime developers like NextEra described the situation as, "We need more plywood and drywall." Most developers appear to have dived back in.

Yield Co Rebound?

MR. MARTIN: So the pipeline of development assets is being replenished.

Limited investment opportunities in Asia are driving more Asian equity investors to look for US investments.

The market was abuzz last year about a number of potential growth areas or rebounds. Let's start with the rebound story. Andy Redinger, you predicted at this conference last year that yield cos would be the comeback story of late 2016 or early 2017. Do you still see that and what does it mean?

MR. BRANDT: Oh, oh. We are being held to our predictions. [Laughter]

MR. REDINGER: Here are some statistics. At this time last year, nobody was accessing the equity markets. Three yield cos tapped the equity markets in 2016, and if you throw Hannon Armstrong in, that's four. If you predicted last year that three yield cos would access the equity markets, everyone would have said no. But they did last year. Yield cos outperformed the S&P 500 last year by 300 basis points.

MR. CODY: Weren't they all private placements or effectively underwritten?

MR. REDINGER: That's right. There is an investor pool that continues to like this asset class, and I think yield cos are a very attractive way for that investor class to participate. Yield cos not only outperformed the S&P last year by 300 basis points, they also outperformed the utility index by 10 percentage points. All but one are trading above their IPO prices by an average of 15% to 16%. I contend yield cos have come back.

MR. MARTIN: Two years ago the big story was warehouse loans to yield cos. Do we see any more of those?

MR. CODY: How about version 3.0? [Laughter]

MR. REDINGER: Listen, I suspect that will come back.

MR. MARTIN: Do you see any new yield cos coming to market?

MR. REDINGER: Currently I do not.

MR. CODY: It would be tough to bring a new one to market today. Obviously the yield co market is too small for an institutional investor looking at possible places to deploy capital. I think at the height of the yield co phase, market capitalization was something like \$12 or \$13 billion. That is one fifth of the size of either of the two largest master limited partnerships. It is challenging for an institutional investor to put money into something

that small versus things that are more easily benchmarked.

MR. BRANDT: The wall of money in the private market continues to be more aggressive than the public market. As long as that dynamic remains, I would think some of the yield cos are considering going private. There are times when the public market trades better than the private market. Right now, the private market is trading at higher multiples. Until that changes, it will be tough for anyone to consider bringing a new yield co to the public market.

MR. REDINGER: And if there are any yield cos who want to go private, give me a call. [Laughter]

MR. BRANDT: One of the things the yield cos have to think about is there could be some activist investors who say, "The private value is higher than the public value. You need to sell off assets, and we will all make money." That has not happened yet, but it very possibly could.

MR. MARTIN: Andy Redinger, last summer you said that independent power producers were trading at \$400 to \$500 a kilowatt in the public markets. Conventional assets were being sold in private deals for \$700 to \$800 a kilowatt. Is the gap still on that scale?

MR. REDINGER: The S&Ps are still trading in that range. That is a broad generalization about conventional power plants. It depends on the asset. On average, if I put hydro, gas and all the rest of it together, that is close to an appropriate metric. I suspect gap has narrowed a little.

But the broader point still holds: the private market continues to value these assets more aggressively than the public market.

MR. MARTIN: Why? Jon Cody, I think you have said before that the private markets are better informed.

MR. CODY: It is easier to make a discreet investment in a project than it is to look at a company, understand fully its prospects and management, and put a value on it. Some of the IPPs accumulated assets pre-renewables and pre-shale gas. It is a much more difficult and challenging analysis when you look at such an IPP. Among the questions you have to consider is whether its capital is optimally deployed. Will its assets continue to generate suitable margins or is there a way by replacing some assets to improve the company profile?

MS. MUTHIAH: I agree with that. The range of IPP valuations right now runs from about \$300 to \$350 a kilowatt to about \$600 a kilowatt. Anyone looking to buy an IPP / continued page 46

Market Trends

continued from page 45

or asset portfolio has to look at the capacity mixes and the geographic dispersion. Looking at a single asset for purchase is a much simpler analysis.

If you look at what transacted this past year, a lot of it was in portfolios where it is hard to tease out the individual values, but it was in the \$550 to \$700 range. Frankly, we do not see a significant dislocation between where the IPPs are publicly trading and some of these private values, but you really need to look carefully at exactly what it is you have. You cannot use simple dollar-per-kilowatt-type indications to come up with a value.

MR. CODY: In at least one of those recent portfolio sales, it was buy three combined-cycle gas turbine projects and we will throw in a coal plant for free.

MS. MUTHIAH: It depends on your view of the coal plant platform. Clearly there are some where the seller just hands over the keys. But there are other coal plants that have better prospects.

Buyers are discounting projected cash flows from solar projects at 7% and wind at 8.5% to 9%.

MR. CODY: Certainly if you are a large formerly regulated utility that is now a massive independent generator, shutting down any of these assets is a complex process with the unions and the states. Transitioning the assets out in some cases just makes more sense.

Potential Opportunities

MR. MARTIN: Let's move to potential opportunities in the year ahead. Community solar has been gradually getting traction, but perhaps not as quickly as some people had hoped. What do you foresee in the year ahead for it?

MS. MUTHIAH: Community solar is still pretty small at only 100 to 200 megawatts in total, but there has been so much growth in residential solar. I think 2016 was the fourth year in a row in which rooftop solar increased by more than 50%. Roughly

half the residential and building sites are not good locations for rooftop solar, so that is the opportunity for community solar. The challenge is there is still a lot of state-level policy making that has to be resolved. There is also a fair amount of complexity. Not all states have programs.

MR. BRANDT: The other thing about community solar, and we sure think about it, is the subscribers are a bunch of consumers and small businesses. There is no investment-grade offtaker. The subscription agreements tend to be short. They allow subscribers to cancel on short notice. You have to be confident that the sponsor can find others to replace subscribers who drop away. The sponsor is also looking for big fees on an upfront basis, and is thinking the whole thing gets done with tax equity and debt.

A financing model will develop that is a lot heavier on equity and that gives the sponsor an incentive to focus on the long-term profitability of the projects rather than short-term fees. These are the things that have been holding back that market. Small stuff has been getting done, but I think there is a real alignment problem.

MR. MARTIN: What about energy storage? We have heard in the past that it will have a transformational effect in the market, but so far standalone storage projects have seemed like a niche market. Do you see any significant growth in storage during 2017?

MR. BRANDT: It is no accident that the guys that are getting some success are people with credit, like AES and NextEra, that have been wrapping themselves and essentially becoming integrators, where they are promising delivery of certain services around their credit rating as opposed to pure project financing.

MR. MARTIN: They have lots of generating assets. They can use storage as a hub for shaping and firming power deliveries.

MR. BRANDT: Yes. I don't think that is an accident.

I think it will remain challenging for anyone else to get traction in the near term. There are a lot of people trying to do it. Tax equity is challenging around it, and the financings are very difficult. We have raised a bunch of equity for some almost-ready technologies that are close to scaling, but it is a thin, tough and difficult market.

MR. MARTIN: Aging nuclear plants are struggling to keep open. New York is handing out zero emissions credits to keep three Exelon plants operating. Illinois has also taken action. Should we

expect a swing back to nuclear under Trump?

MS. MUTHIAH: I think the prospects for new nuclear construction remain very limited. The real question is the extent to which more states will act to keep existing nuclear capacity operating. We are starting to see discussions in Connecticut and Delaware.

One thing about which we have seen no mention whatsoever in all the Trump proposals is the Federal Energy Regulatory Commission. We are going to have a completely reconstituted FERC with three new commissioners. No one knows in what direction the reconstituted FERC is likely to move. Trump's focus is very much on helping coal. It is possible FERC will want to try to level the playing field between coal and other energy sources for generating electricity.

MR. CODY: You have more than 15 intervener groups representing, I think, 60-some-odd different institutions in a proceeding before FERC involving the New York zero emissions credits for nuclear.

MR. BRANDT: I think you will see this litigated not only in the federal district court in New York but all the way to the Supreme Court as to whether the structure that they put forward depresses wholesale market power prices.

MR. MARTIN: Does that litigation have the potential to bleed into state renewable portfolio standards?

MR. BRANDT: The state is subsidizing a specific class of assets. You are always going to have a hard time answering why a small hydro project, for example, does not get the same benefit that nuclear power plant owners are receiving. Hydro is another form of base-load zero emission generation.

MR. MARTIN: So if renewable energy is favored by the state, must the state offer the same benefits to conventional power producers? That would deny states any ability to steer generation to environmentally benign types of generation.

MR. BRANDT: Exelon used the discrimination argument in Illinois to get about \$1.6 billion of subsidies for 10 years.

MR. MARTIN: Trump wants to attract \$1 trillion in new investment to infrastructure. His advisors said last October that he wants an 82% tax credit for equity investors in new infrastructure. Public-private partnerships have had a hard time getting traction in the US, probably because each state has its own program so that a sponsor investing in one state is not able to replicate the model in another state. Is this a real growth area?

MR. BRANDT: We think it is. We think that if you look at the balance sheets of many municipalities, their ability not just to provide new services, but also to maintain existing services leaves a big deficit to be filled. Trump has a lot of ideas. The

market is eagerly awaiting the details.

There has to be a renewal of infrastructure. The municipalities and states are not able to carry the full burden. It is time now to open it up to PPP-type structures. However, the opportunities are likely to remain more niche plays in the near term.

MR. MARTIN: People have been commenting on the great need in this area ever since I have been in law practice, and yet PPPs never get the traction in the US that they have had in other countries.

MS. MUTHIAH: Any push for basic infrastructure in the power sector will focus on the transmission grid. That opens opportunities for some private entities and utilities.

MR. MARTIN: This is the start of a new year. Each of you has been thinking about your own business plans. What have you put on it? Where do you see growth opportunities?

MR. REDINGER: Our biggest initiative -- and this is more about not just this year, but going forward -- is storage. We are investing time and resources to investigate the storage space. Our goal is to be in a position to finance several storage players in the next 18 months.

MR. MARTIN: As standalone storage?

MR. REDINGER: Yes.

MR. MARTIN: Jon Cody?

MR. CODY: We are looking at 2017 as a year when a lot of conventional power plants that are held by financial players will be transitioned to permanent owners. We think the development-and-build cycle for gas-fired power plants will start to tail off and this will lead to more asset-level M&A as sponsors decide it is a good time to transact.

MR. MARTIN: Will buyers have to pay more for assets because of the corporate rate reduction?

MR. CODY: As Ted Brandt mentioned, a lot of these guys are looking at this on a pre-tax basis. They have complex tax positions. As the market moves away from private equity fund investors toward corporate long-term owners, they have existing tax positions that they manage on a more macro basis. Even they do not ask how a particular asset affects their position on an after-tax basis.

MR. MARTIN: Ted Brandt, what is on your business plan? Where do you see growth?

MR. BRANDT: Small and medium-size developers must either raise capital or sell themselves, and we are hoping to be in the middle of such transactions.

MR. MARTIN: Shanthi Muthiah?

MS. MUTHIAH: There is still a lot of / *continued page 48*

Market Trends

continued from page 47

distress in the market, so for us there is a big focus on distressed assets. We continue to see a lot of M&A activity and are very much focused on that. We also see some continued combined-cycle development activity concentrated in PJM. ☉

The Art of the Deal: An Alternative View

by John Schuster, with JLS Capital Strategies in Washington

Home life teaches all the basic negotiating skills that one needs to succeed in the project finance market.

The best learning experiences seem to come during summer and winter breaks. Things inevitably go wrong. The hotel fails to put the cot in the room, or the beach house is located next to a construction site, or maybe we're on a "stay-cation" and the plumbers hired to fix the drain or clean the sofa only make things worse. No problem ever goes away on its own, and because of my negotiation skills, I am the designated fixer.

I have been pleasantly surprised to learn that my daughters – now college age – have been paying attention and can tell me the steps I take to reach satisfactory negotiation outcomes.

Focus

Step 1 in any successful negotiation process is to start with a clear focus on one's needs and interests.

My first learning about the importance of a focus on needs came from my father, most likely the worst negotiator ever. He always seemed to have a complaint, but those to whom he was directing complaints never understood his problem or what he was trying to accomplish. During one episode, a confused desk clerk desperately looked to me to help him understand the problem. Instinctively, I shrugged and gave him a look that said "I don't know what's going on and I can't help you with this crazy guy. He's just my dad" — and dad saw me. That was the last time I was ever caught doing that!

My father was a brilliant doctor, but he violated what I now call the First Promise of the Hippocratic Oath of Negotiation: first, do no harm. He routinely made things worse. I recall my high school experience during Mrs. Ungermeyer's class, when my

friend Kelso and I — both good students — were getting poor grades in an easy class for reasons we considered unfair. Both our parents had meetings. Kelso's meeting was uneventful. He did remedial work and did fine.

During my meeting, my father lost sight of the end game and launched into what some might call a Trump-like tirade, letting Mrs. Ungermeyer know that her intellect, abilities, background, performance, etc. were deplorable, appalling and disgraceful. Dad was probably correct, but the point was to remedy grading issues. An offended Mrs. Ungermeyer never gave me credit for my work and my grade stuck.

The lesson I have managed to pass on to my daughters, who have never shrugged in front of me (or at least never let me see them shrug) is to understand the underlying interests at hand. This is true whether the goal is a discount at the hotel, a replacement beach house not next to a construction site, or timely financial close on a billion dollar deal.

Negotiation is not about winning, but rather about achieving what you need. Those needs have to be understood.

Ask Questions

The second step I did not fully appreciate until my daughters explained it to me. "You make them feel guilty," they said. Except in dealing with my own daughters, I never set out intending to make others feel guilty, but it turns out that I do, and it does help.

I assert the problem, describe how I have been wronged, and explain why the organization has a responsibility to fix it. What I'm really doing is softening my counter-party up to build a platform for negotiation. The "softening" is the guilt. Nobody, not real estate agent James or even night clerk Mike, wants to be the bad guy. Dad's tirade only made Mrs. Ungermeyer angry, defensive and difficult. Calmly and clearly recounting the facts, however, will produce a decidedly different and desirable effect on any responsible person. My daughters see James' posture slump as he gets a guilty expression on his face, which is the cue to move on to step 3.

Before moving on, there is a hidden part of step 2 that I had to explain to my daughters. Step 2 is not just about guilt, but about asking questions and listening. Asking questions may be irritating, but never sours the mood of a negotiation and is almost always informative. Invariably, the dialogue and the answers to questions reveal the available solutions. Night clerk Mike did not respond to guilt and give us a cot. He did, however, explain that the reason why no cot was in our room was a matter of policy rather than fire safety or law. That meant the decision

Three techniques will help lead to a successful negotiation.

could be changed by his manager.

During the one and only time I have asked about one of my daughter's grades, rather than repeating the Ungermeier incident, I asked questions. In so doing I learned — and the teacher realized — that the grade reflected information from a prior period that was no longer relevant and that my daughter had done extra work to merit extra credit. Problem solved.

On billion-dollar financings, I have been able to construct remedies I would never have thought of had I not kept asking questions. You will never know what solutions are available until you ask questions, listen carefully to the answers, and follow up attentively.

Elevate

Step 3 is one I must use a lot, because when I asked my daughters what my next step is, they replied instantly and in unison, “you ask to speak to the manager.” Whether I always do this, following up with other parties is always an option. Chain hotels rarely give night clerk Mike authority to make a change and the manager must intervene. Or raising the specter of the manager is necessary in case Mike has the authority and just needs the extra push and will fix the problem to avoid consulting his boss.

Here are some rules of thumb about when to use the “manager card.”

Only use the card if you need to. Despite my girls' observation, I do not speak with the manager unless I need to, in part because it harms relationships. Real estate agent James wanted to do the right thing, happened to have a last-minute cancellation for a house not next to a construction site, and was able to help us. James kept renting us that house for years. When I was the “manager” at the US Import-Export Bank, borrowers would appeal to me, but I discouraged the practice. Better to work things out with the project officer, who was the borrower's primary relationship.

Only talk to the manager after a proper dialogue with the principal. Ask direct questions, listen to answers carefully, follow up as necessary and clarify all you can. When you do speak with

the manager, you will seek solutions that are institutionally feasible and practical. On large infrastructure deals where the time and attention of senior managers is limited, you get one shot and a short period to talk to the manager. Do your homework and ask for the right thing.

The “manager” is not necessarily the boss, but someone who can help you. When Dwayne the plumber only made things worse, he was effectively the manager and no one at his company would help us. The manager then became our insurance company. Insurance gave us the tools to conduct a proper investigation, pay to solve the problem, and pursue a settlement from Dwayne that covered all our costs. Amazingly, the key to using insurance effectively is the willingness to ask questions and submit to a fact-based process (Step 2 again). On large infrastructure deals involving commercial banks or export credit agencies, the “manager” might be a major exporter or the sponsor, who can improve contract terms, assume risks, and remind the lenders of the deal incentives and the risks they are taking.

The last step to mention in this process is to write a formal letter, memo, or presentation. I am famous for having drafted the perfect letter of complaint following a disappointing meal at a top-flight restaurant I genuinely loved (and still love). The letter was a time-consuming work of art, which recounted the specific details of my history with the restaurant and the courses of the meal, and resulted in a free dinner for four worth several hundred dollars. On infrastructure deals, I have used carefully scripted presentations or short and pointed memoranda to crystalize issues to great effect.

A few provisos on the written word: first, written material can be effective, but takes time, and should be used judiciously. You may use the written word as directed by your principal relationship, who may want something in writing to help him with his or her bosses. Otherwise, use written complaints only as necessary, once other measures have failed. Written treatises are the exception.

Second, choose your words carefully. Anything written has to be very carefully scripted and stand on its own. Be mindful of anything that might upset anyone, especially on large infrastructure deals where people tend to get nervous. If you think there is a chance you will offend someone, you probably will. Think again and re-draft.

/ continued page 50

Art of the Deal

continued from page 49

No High Fives

That's the process. It is simple, straightforward, specifically designed to "first do no harm," and is almost always successful.

So why isn't it used more often? Why are forceful, Machiavellian techniques considered more prevalent?

First, this process is used fairly often. Many of the same underlying principles stated here are the same as in the *Harvard Negotiation Project* and *Getting to Yes*.

Second, this technique is not exciting or sexy. The process involves thought, effort, listening, and creativity, and generally does not result in big wins that are followed by the slapping of high fives or boasting about winning. Understanding the components of my daughter's grade and the teacher's grading process took time and careful listening, and in the end, my daughter only got what she deserved. By submitting to the insurance process to solve the plumbing problem, we chose to give up on a potentially lucrative suit. The replacement beach house and even the lovely meal for four were all only things one should expect from reputable parties. Many of results on infrastructure deals are largely the same. Getting to financial close in a reasonable period, avoiding prepayment penalties that should not apply, and avoiding unnecessary due diligence are all things one should get.

Why invest all that effort just for fair treatment?

The reason is because avoiding unnecessarily bad outcomes is what most negotiations are all about. At home, I am only the fixer when there is a problem to be fixed. At work and especially on infrastructure deals that involve long relationships among parties, scoring the big win may be injurious in the long run. Over-reaching leads to bad feelings, renegotiated deals, and ultimately worse outcomes for both parties. If parties can avoid unnecessary requirements, pay a fair level of fees, and achieve a sustainable deal, that is a win.

Postscript: the stories are all true. The names have been changed to names of popular fictional characters. Anyone identifying all of them spends too much time on TV, movies, and the internet. ☺

Solar Tax Equity Update

Solar passed wind as the largest share of the US tax equity market in 2015, but appears, based on preliminary numbers, to have slipped behind wind in 2016. The year ahead could be challenging. Congress will spend a good part of the year rewriting the US tax code. A panel talked at the Solar Energy Industries Association annual tax and finance seminar in Washington in December about the potential effects of tax reform and other new developments on the market and what to expect in 2017.

The panelists are Julian Torres, a CFA and director at RBC Capital Markets, a Canadian bank affiliate that is active in the US tax equity market, Martin Pasqualini, managing director of the CCA Group, a prominent tax equity advisory shop, and Jonathan Plowe, managing director of Tax Equity Advisors, which acts as both an advisor and a principal in investing. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Jonathan Plowe, what effect do you expect Donald Trump to have on the tax equity market?

Trump Effect

MR. PLOWE: The reaction so far to the Trump election is a little like the five stages of grief. It is initially stunned silence followed by a brief period of panic, and then graduating to a bit more comfort that the world is not coming to an end -- until yesterday's tax reform panel, when I think we may have tipped back to fear again.

Tax reform is the big question mark. We need to see what will come and when it will be effective. People have started to take a much closer look at how tax law change risk is being allocated and the protections for the tax equity investor.

MR. TORRES: We have seen significant growth in speculation about tax reform. The Trump election has caused some investors to pause. Some deals may be restructured or repriced that were not fully committed before election day. Trump's win has given us a chance to consider tweaks to structures in anticipation of tax reform.

MR. MARTIN: How do you tweak the structure?

MR. TORRES: There is a list of fixed tax assumptions in partnership flip transactions that are risks that the tax equity investor takes. In most deals today, the tax rate tracks the investor's actual rate in effect at any given time. However, there are still a few

deals where the tax rate is locked in and is a fixed tax assumption. Trump's win is causing people to adopt a floating tax rate and to think about whether it is even appropriate to size the tax equity investment on the basis of a 35% tax rate.

MR. PASQUALINI: For deals with construction debt that have a tax equity takeout of \$100, you plug in a 15% tax rate and the tax equity amount falls to \$80 ignoring a host of other issues that present themselves due to the rate change.

Lenders want a floor on how much the tax equity amount can be adjusted for tax rate change, and they want more substantial shortfall guarantees, shortfall LCs. They also need to have essentially an alternate structure ready, locked and loaded, and pre-agreed, if the tax rate changes. Over the last week, we have seen lenders asking to address not only rate change but also draconian slowdowns in depreciation rates. It will be up to the sponsor ultimately to plug any gap in funding.

MR. MARTIN: Various reporters have been asking in the last week whether the tax equity market has shut down. Marty Pasqualini, you are shaking your head no.

MR. PASQUALINI: Next week, we will close our sixth new commitment since the election.

Tax Change Risk

MR. MARTIN: Since the election, it seems like there have been three areas of tension in deals. One is corporate rate change, which Julian Torres and Marty Pasqualini mentioned. The second is the possibility depreciation might change, but whether for the better or for the worse is a little hard to tell. Republicans want to accelerate depreciation. The third tension is in deals with multiple fundings. There is a debate about how far along in the legislative process a proposed adverse tax law change must have moved before the tax equity investor can stop funding.

Do any of you have other items to add to the list?

MR. PASQUALINI: A number of potential tax law changes are in play that affect the economics in tax equity deals. There are different levers you can pull to influence the internal rate of return to the tax equity investor and that will affect the amount of tax equity that can be raised. The levers include the percentage of project cash flows that go to the tax equity investor, how you allocate the tax items, and the size of the deficit restoration obligation. The levers will have to be adjusted to optimize the structure for sponsors and tax equity investors once it becomes clearer what tax law changes Congress is likely to enact.

MR. MARTIN: Your point is the basic economics may change due to changes in depreciation and the corporate tax rate. Let's

focus on the corporate tax rate. Does a drop in the corporate tax rate necessarily mean less tax equity can be raised? In a partnership flip transaction, maybe you have four years of losses and six years of income.

MR. PASQUALINI: It depends on the particular transaction. The negative effect of a tax rate change that hits in the first three years of a wind deal far outweighs the benefit of a reduced tax rate in the out years when the project is tax positive. In a solar deal, if the tax rate change does not take effect until after the first year, generally you are good.

We have run countless sensitivities to show the effects of rate changes on the internal rate of return, net present value and duration risk for the tax equity investor.

MR. PLOWE: We had a period of time between the election and year end when deals had to close. If we lived in an alternate universe where the US elections happen in January, we would have had a much more pronounced pause that could have been detrimental.

MR. MARTIN: Julian Torres made the point that sponsors are taking the risk of tax rate change, and I think that has been true for at least the last two or three years. Lately, tax equity investors have also been making sponsors take the risk that the depreciation calculations will change. The House Republicans are talking about accelerating depreciation. In view of this, are tax equity investors better off locking in the current depreciation that they used for purposes of pricing? The actual depreciation might provide an upside.

MR. TORRES: Maybe. Our sensitivity analyses suggest that the detriment from the tax rate reduction will far outweigh the benefit from faster depreciation.

Tax equity investors build a portfolio that seasons over time. We are seeing that more seasoned investments will actually benefit from the reduction in the tax rate. The newer projects take a hit. A yield-based partnership flip is highly protective to the overall return.

MR. PLOWE: When you look at a partnership flip structure with a variable tax rate in the fixed tax assumptions, a sponsor with back-leveraged lenders that need to be comfortable still has a lot of flexibility with the flip date because most of the debt structures today are relatively short term. The focus of the back-leveraged lenders is less on the long-term value of project cash flows than on the first several years.

I think the impact might be more pronounced on equity values of solar sponsor entities over the longer haul. The partnership flip structure mitigates some of the

/ continued page 52

Tax Equity

continued from page 51

impact of changes in tax rate and depreciation.

MR. MARTIN: Do you agree or disagree with the following? The tax equity market will remain open for business. This is what the tax equity shops do for a living. They will find a way to continue doing it. However, tax equity will make up a smaller percentage of the capital stack after the corporate rate reduction. Sponsors will have to fill in the gap with more debt or equity.

MR. PLOWE: I agree, but I also think that there are a few headwinds on the use of tax equity for sponsors, including an increasing percentage of direct sales of solar rooftop systems as rooftop solar companies, especially the publicly-traded ones, try to develop a better GAAP and cash profile for their businesses.

Tax-change risk is the biggest issue this year in the tax equity market.

However, if the industry continues to grow rapidly, you should still see an increasing need for tax equity even as the percentage of third-party-owned systems as a percentage of total installations declines.

MR. MARTIN: Do you agree that tax equity will be a smaller percentage of the capital stack?

MR. PLOWE: I am not so sure. Tax equity investors need to invest a certain amount to make a transaction efficient. If there is a drop in the corporate tax rate, you end up asking tax equity investors who are loathe really to rely on the project's credit to take more cash to reach their returns.

Most established investors want to make this look like a tax product and to the greatest degree possible mitigate their exposure to project cash flow. If we have a sea change in the makeup of the return, you may see a displacement of the traditional financial investors.

On the other hand, you can argue that the traditional investors will still find a need for shelter. If their effective tax rate ends up at 20%, they will still look for ways to reduce it to 15% because

that is what they are supposed to do for their shareholders.

Or we could see more of what we saw a lot of last year in the utility-scale solar space, which is the strategic investors who were tax efficient provided the tax efficiency to the deal because they want to be long-term owners and understand the cash flows. That is the business they are in.

Market Size

MR. MARTIN: Preliminary estimates are that the solar tax equity market was just under a \$5 billion market in 2016. There have been suggestions that 2017 may be slower. What do you think?

MR. PLOWE: Anecdotal evidence suggests that the market will continue to grow. We committed \$300 million of capital just a few weeks ago with about a 12-month deployment time frame on it. That will already be about half spent as of the beginning

of January. The pace of deployment in the distributed generation space remains pretty impressive.

MR. MARTIN: I stopped counting the number of tax equity investors at 35 in the summer 2015. It seemed like there was a new one every three to four weeks in 2016. Do you expect this pattern to continue into

2017?

MR. TORRES: There are 70+ institutional and corporate investors in the affordable housing market and some have started to shift their attention to renewable energy. We see at least three to five investors coming over from that side who are completely new to renewable energy.

MR. MARTIN: I know in the past, new investors were reluctant to dive in because they thought the tax credits were temporary. Why waste time learning about something that will disappear? Do you think the prospect of corporate tax change will cause people to say this is not worth the effort?

MR. TORRES: The long-term extension of the tax credits in late 2015 got a lot of investors to think about dedicating the resources necessary to understand a new asset class. However, it is two steps forward and then one step back with tax reform. Now is the time to educate new investors about how structures work, and in particular how the yield-based partnership flips work, since the investors have a reasonable expectation of eventually reaching their returns, assuming the project continues to operate.

That should give them comfort to proceed cautiously.

Other New Developments

MR. MARTIN: What other new developments have there been in the market? We talked about Trump. He is the biggest new development. What is next?

MR. PLOWE: Some of the biggest tax equity investors that deploy billions of dollars in the market may be starting to test limits that have nothing to do with tax capacity. Even if corporate tax rates are lower, there is plenty of tax capacity in that group of investors, but there is a sector exposure issue for some large tax equity investors, which is yet another reason why we need to continue to see more new entrants come into the market as we have over the last couple years.

MR. MARTIN: Are you saying that there are some sizeable investors who have reached their limits on exposure to certain sponsors?

MR. PLOWE: Not necessarily reached the limit, but the solar sector has grown very rapidly and some big investors have increased their exposure to that sector through both debt and tax equity in the last couple years. We are more likely to see senior management and risk managers say, "Let's pause a little and think about the size of our exposure and see how we can prioritize our client-facing businesses around some limits."

MR. PASQUALINI: There is an inconsistency in how some larger investors think. They tend to prefer established relationships. Some of these transactions are large. The aggregate exposures are large. Many of the larger investors had significant exposures to SunEdison. There is probably a bit more attention being paid by the folks who write the biggest tickets to their exposure levels to individual sponsors.

MR. TORRES: We see two camps of tax equity investors in the partnership flip market. One camp is focused on keeping as short a tenor as the tax rules allow for the targeted flip date, and the other camp is pushing out the target flip date and monetizing more cash. There are good reasons for either approach. They can co-exist.

MR. MARTIN: Why would a sponsor want to monetize cash at a higher tax equity yield than it could through back-levered debt?

MR. TORRES: If you think about the cash-on-cash return as a normal investor would, and not as we think about it for satisfying IRS regulations, it is a negative return. The amount of cash that tax equity investors take against the upfront cash investment typically results in a negative IRR when excluding tax benefits. So I think that it is cheaper to monetize cash in the tax equity

market than through back leverage.

MR. MARTIN: It seems like there has been a shift to partnership flips and away from inverted leases and sale-leasebacks in solar. Do you agree?

MR. TORRES: That has been the general trend.

MR. MARTIN: What is driving it?

MR. TORRES: Banks, who are the largest number of tax equity investors, want to have shorter tenor investments. The sale-leaseback requires valuing the residual and fighting over what it is worth with the sponsor. It also is a credit structure, whereas the partnership flip is an equity structure. So you manage the risk differently in the two structures. Also, the accounting treatment for sale-leasebacks is not as good.

MR. MARTIN: And may be changing for the worse.

MR. TORRES: Correct.

MR. MARTIN: What percentage of the capital cost of a typical residential solar, C&I solar or utility-scale solar deal is raised through tax equity?

MR. TORRES: I see between 35% and 50% generally in the ITC world. On the residential side, depending on how many prepaid contracts you have, you may be solidly in the 40% range. In the C&I world, you are at the lower end. The perception in the market is they are riskier and, therefore, require a higher yield. The higher the yield, the less tax equity that is raised.

On the utility-scale side, you see much higher advance rates. People feel more comfortable with the projected cash flows with a A-rated utility as the electricity offtaker. You have high-grade builders under EPC contracts and experienced O&M contractors, so the cash-flow stability is accretive to the advance rate.

Basis Risk

MR. MARTIN: The biggest tax risk in the solar market is the tax basis used to calculate the tax benefits. How common is it today for a tax equity investor to put a cap on how large a markup it is willing to see above the actual cost to construct? Does anyone think the market is coalescing around a general rule of thumb and, if so, what is it?

MR. TORRES: We do not have a set rule of thumb. It is a case-by-case analysis.

MR. PASQUALINI: I think that 10% is a general guideline, but some investors are willing to go as high as 20%. There are circumstances where the investors will go higher if you can clearly support the higher value. Investors invariably get a basis indemnity from the sponsor.

MR. MARTIN: Sponsors for the most / continued page 54

Tax Equity

continued from page 53

part are trying to keep a larger share of cash and monetize it through back-levered debt. This creates tension between the tax equity investor and back-levered lender. They are like two farmers relying on the same river to irrigate their crops. The back-levered lender is downstream and wants to make sure all the water is not taken out before it reaches him.

Julian Torres, how accommodating are you as a tax equity investor to the needs of the back-levered lender? Will you set aside a certain amount of cash to pay principal and interest on the debt?

MR. TORRES: We can be accommodating, which is to say back leverage is back leverage for a reason. It is subordinated to tax equity. There is a risk premium built into the pricing for that type of debt.

MR. MARTIN: Are you seeing tax loss insurance and, if so, covering what risks?

MR. TORRES: I have only seen it in support of securitizations to protect against sponsor failure to make good on indemnifications for basis risk. The policies are specifically geared toward that single risk.

Potential New Areas

MR. MARTIN: Julian Torres, you just closed a community solar deal. What special issues did it raise?

MR. TORRES: The special issues were about how subscribers are managed. What kinds of contracts and what terms are offered? Is there standardization across contracts? We just closed a community solar transaction after looking at a lot of other portfolios. The one we closed was the most homogenous one we could find. It was geared toward highly rated municipal off-takers and subscribers and partners that have strong balance sheets.

MR. MARTIN: One more question from me, and then let me ask the audience if it has any questions. There has been talk about combining PACE financing with tax equity. Have you seen any such deals?

MR. PLOWE: We see a lot of prepaid power contracts in the residential solar space. One must assume a portion of those may be financed with PACE loans, but we have no visibility into that. That is all handled outside of our purview.

MR. MARTIN: Is it attractive to tax equity investors if you can somehow use the property tax enforcement mechanism to ensure that customers pay on time? Will that result in a lower tax equity yield?

MR. PLOWE: Even if it is attractive, I doubt it will result in a lower yield. One thing about PACE is that so far the scale is not large. Some of those laws have been around for a while. We have seen a couple securitizations of PACE paper, but it will take time before PACE becomes a big component of the tax equity market.

MR. MARTIN: Please stand up and say your name and affiliation.

MS. CRAFT: Lauren Craft with SunEdison. C&I is an especially tricky sector. Are you seeing any efficiency gains recently with the deals that have been coming across your desks?

MR. TORRES: The portfolios tend to have an extremely wide range of credit quality. You can have AA-rated municipalities and unrated off-takers in the same portfolio. It is difficult for sponsors to reach needed volumes.

MR. MARTIN: Please say your name and affiliation.

MR. FRAGA: Chris Fraga with Alternative Energy Development Group. Can you comment further about the tax equity's view of prepaid power contracts?

MR. PLOWE: When I was speaking about prepaid PPAs, I was speaking specifically about residential solar prepaid PPAs. Generally, we view them as a form of leverage. They are not a source of any ongoing cash flow. This affects the sensitivity of how the deal performs under different scenarios and how tax reform and all the other things about which we have been talking affect the transaction. For example, if depreciation is worth less because the corporate tax rate is reduced, prepaid PPAs mean there is no additional cash to shift in the out years to the tax equity investor to make up the loss. Tax reform may prove the biggest headwind for prepaid deals. ☹

Environmental Update

Congress and the Trump administration are moving to reverse a number of environmental regulations that affect the US energy sector.

Congress invoked the rarely used Congressional Review Act in early February to nullify a regulation limiting the venting of oil and gas wells on federal lands. The regulation, issued by the Department of the Interior, restricts flaring of gas leaking from wells on public lands in order to limit methane emissions that contribute to global warming. Methane is roughly 30 times more potent than carbon dioxide as a heat-trapping gas.

Congress also vacated restrictions that the Department of Interior imposed last December on discharging waste into

streams and rivers from a form of coal mining called mountaintop removal.

The Congressional Review Act gives Congress the power to withdraw regulations within sixty legislative days after the regulations were issued by federal agencies. Removal requires a majority vote in both the House and Senate. The 60 legislative days in this case stretch back to mid-June 2016. As many as 200 regulations issued in the second half of 2016 may be at risk. Congress has until early June 2017 to act. Removal of a regulation then bars the federal agency from issuing any “substantially similar” regulation in the future without Congressional approval. Congress had previously used the Congressional Review Act successfully only once, 16 years ago, to overturn a Clinton administration rule. The statute has never been tested in the courts.

These are first steps being taken by Congress and the new Trump administration to erase the Obama administration’s environmental regulatory legacy. As the 60-day window closes on new rules, opponents of environmental regulation will have to rely on other tools. One approach will be to cut funds and staff available for agencies to enforce the law, or to attach more targeted appropriations riders to legislation. Once the Trump team is in place, the agencies themselves can rewrite existing regulations, although the same time-consuming procedures will have to be followed to ensure consideration of conflicting points of view that applied when the regulations were first issued.

Climate

The Trump administration quickly removed information about climate change from the US Environmental Protection Agency website, but dismantling the Obama Clean Power Plan and a series of other measures to reduce US greenhouse gas emissions will take more time.

Underlying each of these measures is an “endangerment finding” by EPA in 2009 that greenhouse gas emissions endanger public health and welfare. The finding followed from a 2007 decision by the US Supreme Court in a case called *Massachusetts v. EPA* that carbon dioxide is a regulated pollutant under the Clean Air Act.

Unless Congress amends the Clean Air Act to state that greenhouse gases cannot be regulated as pollutants, or the Trump EPA successfully revokes the endangerment finding, then some level of greenhouse gas regulation is legally required.

Trump advisers have suggested the new administration may

simply dial back climate regulation to a minimum level rather than try to eliminate it altogether so as to put the government in a better position to defend against the inevitable legal challenges while still achieving the same outcome. This tactic could arguably upend common law claims that are currently pending in state courts against emitters.

Whichever approach EPA chooses, killing the Clean Power Plan — the agency’s regulatory scheme for regulating greenhouse gas emissions from power plants -- is on the to-do list. Scott Pruitt, the incoming EPA administrator, told a Senate committee during confirmation hearings: “The Clean Power plan did not reflect the authority of Congress given to the EPA.” He said EPA went beyond the authority given to it in the Clean Air Act by trying to base emissions reduction targets on measures taken “outside the fence line,” as opposed to limiting the regulation to actions that can be taken at the plant itself.

Pruitt was most recently the Oklahoma attorney general. In that post, he filed lawsuits to block not only the Clean Power Plan, but also EPA regulations limiting mercury emissions from power plants and a regulation claiming broad jurisdiction for the agency to attack water pollution under the Clean Water Act.

New Script

Trump’s nominees to head various government departments took a more measured tone on climate change before the Senate during confirmation hearings than President Trump did while on the campaign trail.

Trump was a severe critic of US government efforts to deal with climate change. He called global warming a “hoax” invented by the Chinese.

Scott Pruitt told the Senate committee considering his confirmation, “I do not believe that climate change is a hoax” and “[s]cience tells us the climate is changing and human activity, in some manner, impacts that change.” The nominee to head the Interior Department, Ryan Zinke, followed a similar script. Former Texas Governor Rick Perry, who will head the Department of Energy, reversed years of asserting that the science behind climate change is “unsettled” and a “contrived, phony mess.” Perry said, “I believe the climate is changing. I believe some of it is naturally occurring, but some of it is also caused by man-made activity. The question is how do we address it in a thoughtful way that doesn’t compromise economic growth, the affordability of energy, or American jobs.”

Notwithstanding the change in tone, the new

Environmental Update

continued from page 57

administration is still expected to reverse course on regulation to address climate change. The argument going forward is expected to be that the science is uncertain as to what degree the climate is changing, to what degree that change is occurring as a result of man-made activity, and whether those changes will result in any harm. Pruitt said during his confirmation hearings, “The ability to measure the precision, degree and extent of the impact and what to do about that are subject to continued debate and dialogue.”

Science

There are fears that the Trump administration will withdraw scientific information from government databases and cancel research into climate change.

The Obama administration issued guidance on estimating the climate impacts of federal decisions. Such effects may no longer be taken into account in federal decisions if proposed changes are implemented.

The National Aeronautics and Space Administration has played a role for three decades in climate-change research. NASA satellites track melting ice sheets and rising seas. Former Congressman Bob Walker, who advised Trump on space policy during the campaign, argues that NASA should no longer conduct climate science and calls the agency’s actions a form of “politically correct environmental monitoring” that is better done by the National Oceanic and Atmospheric Administration, which monitors the weather.

Myron Ebell, who headed the Trump transition efforts on environmental issues, told reporters on January 30, 2017, that President Trump is likely to pull the United States out of the global Paris climate agreement. However, there has been no announcement, and Trump told former President Obama when the two met in November that he would keep an open mind.

Ninety-four countries, representing 66% of global greenhouse gas emissions, have ratified the Paris accord to address climate change after more than two decades of effort. They include the three biggest emitters: the United States, China and India. The agreement officially went into effect in November 2016. The countries agreed collectively to limit the increase in global temperatures to no more than two degrees Celsius (3.6 degrees Fahrenheit). Scientists believe it is too late to prevent any increase. ☹

— contributed by Andrew Skroback in Washington

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