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PROJECT FINANCE

NewsWire

April 2016

Learning From Venus

by John Schuster, with 32 Advisors in Washington

Even 50 years into the women's liberation movement and even with increasing numbers of women at the negotiating table, women are under-represented at senior levels of finance companies, and views about how to conduct finance and business negotiations remain decidedly male-dominated.

When I first started at the US Export-Import Bank, my wife would ask me regularly whether I had "kicked banker butt."

Donald Trump's high-handed *The Art of the Deal* approach continues to typify conventional wisdom about deal making. To succeed, women need to be as or more aggressive than men to be taken seriously. In an upcoming film at the Sundance Festival, the film *Equity* about female investment bankers is being heralded as "the first female-driven Wall Street film." The female lead characters are tough, aggressive and even ruthless.

Both men and women can and often should be tough and aggressive, but the continuing focus on attributes typically associated with men too often sends the message that, to succeed, women need to be men.

This type of conventional wisdom leads all of us — men and women — to overlook that four of the most important and undervalued assets in project finance involve skills more commonly associated with women rather than men. They are juggling a dynamic deal environment, initiating a dialogue, seeking consensus and win-win situations, and listening carefully to others. As with being tough and aggressive, these four skills are not the exclusive purview of either men or women — only more commonly associated with women — and something we all benefit from learning.

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MEXICO has scheduled the next auction for long-term power contracts for August. Bidders will be invited to participate in April.

Contracts to buy power from 2,191 megawatts of solar projects and 562 megawatts of wind farms were awarded at the end of March. The August auction is expected to be 50% bigger. The deputy secretary of electricity told a Bloomberg New Energy Finance conference in New York in early April that the government hopes hydroelectric and combined-cycle gas projects will do better in the August bids.

The winning bidders in the March auction offered to supply solar electricity at a lower average price than wind electricity.

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Well Trained

My way of thinking about these skills and my personal basis for a female-centric focus come from experience as the former head of the project finance division at the US Export-Import Bank during a period when the bank was led by female managing directors and had just emerged from a period of being run by one of the most important women in project finance. I am also the father of two daughters who can do anything to which they set their minds. My oldest daughter reminded us at her bat mitzvah that a girl can do anything a boy can do and do it in high heels.

A review of the basic project finance concept is helpful to understanding why project finance benefits from strengths commonly associated with women.

Limited or non-recourse project finance is a form of finance in which financing is extended on the basis of future cash flows of a new project. Banks lend hundreds of millions of dollars or even billions of dollars to projects that are often just a site with nothing built on it. I used to refer to it as financing something from nothing, but it is far from nothing, as project finance involves complex financial analysis, extensive documentation, and substantial equity at risk. Project finance is not for the faint of heart and it is very time-consuming, but it has produced good outcomes and is great fun for us deal junkies.

There are at least four skills typically considered female strengths that are important for project finance.

Skills more commonly associated with women are needed in project finance.

Juggling

The complex set of relationships involved in a project financing requires a lot of mental juggling.

Everything in a project financing is related to everything else, and one has to hold a lot of constantly changing terms and concepts in one's mind, all at the same time. The commercial relationships governing project construction have a bearing on how the project will be operated, which is tied to the supply of fuel or other critical materials. The strength of the sponsor has a bearing on project risk, and all of this affects how much money is needed in reserves, which ties into project cost and debt needs, which then affects debt coverage and equity needs. These all affect debt covenants, which in turn affect project equity cost and returns.

The details go on and on and back and forth, all the way to specific conditions and the exceptions to these conditions and the carve outs to the exceptions.

One must be cognizant of the impact of individual elements of a deal when making changes to another, and maintain a mental image of a dynamic set of inter-connected relationships.

At the risk of generalizing, by and large women have become better jugglers than men. The typical working mother makes sure that kids get where they need to be, do their homework, and eat healthy food, all while succeeding in a full-time job in the formal workplace. Many men's idea of juggling is reading emails while on a conference call.

Dialogue

Project finance thrives on and requires a great deal of dialogue.

Every deal is different and no one individual is ever the master of all one needs to know. The only way to move forward constructively is to ask questions, raise issues for discussion, seek expert advice, and then ask more questions.

I am constantly surprised by how little emphasis is placed on the process of dialogue and how much is missed in all stages of the deal process as a result. Once during due diligence on a

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petrochemical deal in Asia, banks were set to accept feedstock supply risks without even exploring what kinds of support strong sponsors might offer — until our side broached the question. A dialogue ensued, and the issue was resolved.

During the documentation stage of another deal, the borrower wished to avoid a prepayment penalty and argued on the basis alone that the borrower did not want this penalty. The borrower ultimately relented on the point, figuring (incorrectly) that the circumstances would never arise. The borrower never initiated a dialogue and never explored the reasons for the penalty. If the borrower had done so, then both sides would have realized the penalty was a mistake, an unintended consequence of legal drafting that the lender would have corrected had there only been a discussion of the underlying circumstances. Only much later and at a cost of time and expense to the borrower did the parties revisit the issue and remove the penalty.

Consensus

Negotiation is rarely about winning and losing, and this is especially true in project finance, where deals have long lives and can be likened to long-term commitments or relationships.

If one person's win translates into someone else's loss, then the long-term relationship becomes unstable and the deal may fail. It is better to engage in a process to understand and seek mutual long-term gain.

Erik Woodhouse's *Political Economy of International Infrastructure Contracting, Lessons from the IPP Experience* provides a very useful way of thinking about winners and losers in project finance. Woodhouse organized outcomes on independent power projects into four categories according to binary outcomes of good or bad for two parties: foreign governments and private developers. About three quarters of all deals were clustered around one of the four categories, deals that were good for governments and developers.

The best way to get to that outcome is through a respectful process of understanding and managing everyone's interests. Seeking consensus and win-win outcomes are better for the parties in the long term.

Listening

Careful listening is critical to project finance. As with initiating dialogue, I am constantly amazed by how much is missed by failure to listen carefully to the totality of what the other side is saying.

The interests behind the positions one side */ continued page 4*

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The average price for solar was $50.73 a MWh for a package including both energy and clean energy certificates, called CELs, while the average price for wind was $58.99, according to the Energy Ministry.

The auction had to be rerun because the price algorithm was originally run without regional adjustments. The adjustments helped projects in Yucatan state make the final cut.

There were 227 bids from 69 companies. Eleven companies were awarded a total of 18 contracts: 12 for solar and six for wind.

The contracts start in 2018, but must be signed by July this year. They are with an affiliate of the Comisión Federal de Electricidad. They provide energy payments for 15 years and the right to sell CELs for 20 years.

The government expects that winning projects will require $2.6 billion in investments.

PPA payments may be denominated in pesos or US dollars. If in pesos, 30% of the price will be adjusted for inflation and 70% tied to the exchange rate for the US dollar, making it possible to finance projects with dollar-denominated debt. This may lead to dual-tranche financings, with a commercial bank tranche, possibly for as long as 15 years, and a development bank tranche of up to 20 years. Lenders are already in talks to provide financing.

The biggest winners were Enel Green Power and SunPower, which won contracts for three solar projects each, in the case of Enel with a combined capacity of 787 megawatts and in the case of SunPower with a combined capacity of just under 900 megawatts. These projects are expected to generate more than 60% of what the CFE agreed to buy at auction.

Total generating capacity in Mexico was 62,233 megawatts at the end of 2014.

A new law in December sets renewable electricity targets at 25% by 2018, 30% by 2021 and 35% by 2024. Mexican installed capacity was 25.3% renewable energy in 2015, but renewables accounted for only 18.2% of output.

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articulates are often as or more important than the answers themselves. That is where one finds the basis of a deal. A lender may be asserting the need for a sovereign guarantee, but the key interests may be credit support that could come from a private party or government participation, which may come from a public non-sovereign. A lender may be concerned mostly about liquidity, but may assert low debt leverage as a way to get there, which is a very inefficient way of addressing liquidity concerns.

The point is not that all women are better listeners and native-borne jugglers of project finance or that men cannot be successful project financiers. Rather, all types of deals — and especially project finance deals — involve a long-term process with several parties and complex relationships. Skills and attributes most commonly associated with women — skills that are typically undervalued — are critical to success. ◎

Solar Securitizations: Practical Advice

by Andrew Coronios, in New York, and Keith Martin, in Washington

Solar securitizations may see a hiatus for part of 2016 in anticipation that equilibrium will be restored in the debt capital markets. Seven deals have been completed, with the blended yield rates on the SolarCity deals completed in late January and February rising to 5.81% and 6.25%, with 74% or 75% advance rates, compared to debt rates in the low 4% range for earlier SolarCity securitizations. The higher rates reflect the volatile market conditions of late 2015 and early 2016. Asset-backed securities or ABS spreads reached a 3-year high in January. Issuers may wait to resume offerings until the markets calm down.

The trend has been to focus on residential, rather than commercial and industrial, portfolios because of the stronger interest in residential portfolios in the market.

The rooftop market is shifting toward direct sales with financing often provided by the developers. This should make securitizations easier by eliminating the complexities of layering securitization on top of tax equity.

Back-levered debt is being used in combination with tax equity structures at LIBOR plus 250 to 350 bps to bridge to securitizations.

SunPower announced that it anticipates its first securitization to close in the first quarter of 2017, a little later than the market expected. The company has been putting assets into its yield co, 8Point3, as an alternative to going to the ABS market.

Speakers at a Standard & Poor's roundtable in January on the solar ABS market said interest in the solar asset class is booming. The solar sessions at the annual ABS industry conference in Las Vegas in March attracted standing-room-only audiences.

At least two or three new issuers are expected to enter the market by the end of 2016 in addition to those that have already done securitizations. Annual deal volume could also increase in 2016 despite the hiatus. There were two transactions a year in 2014 and 2015. There have already been two deals in 2016.

Practical Advice

Here is some practical advice to solar companies that are thinking about doing a securitization for the first time.

Think about the assets that would be in the securitization pool. The market has indicated in its responses to securitizations to date that a pool that is as standardized as possible is preferred. The initial SolarCity securitizations were mostly residential systems with a minority of commercial and governmental customers (up to 29% by value). Later transactions by both SolarCity and Sunrun were exclusively residential. Residential as a class has been well received in the market. While there have been attempts at securitizing pools that are exclusively or predominately commercial and governmental customers, there have not been any successful transactions to date, so there is less of a clear path both with the rating agencies and the market on securitizing commercial and governmental customer contracts.

Do you have a large enough pool of customer agreements? The smallest solar securitization involved around 6,000 customer agreements. The others have been larger with as many as 16,000 customer agreements.

The customer agreements within the pool should be substantially consistent in format as well as on key legal and business terms. Standardization is key. The securitizations to date have been done by developers who originate their own customer agreements so there is a high degree of consistency across the customer agreements. Trying to securitize a pool with diverse customer agreements is more challenging.

The company must have the infrastructure to be able to produce detailed historic and current asset information, both in terms of IT and accounting systems and personnel.

Rating agencies will do a detailed analysis of PV system production historic performance and manufacturers of panels and inverters, historic customer performance and loss and delinquency data, underwriting and credit policies (both for origination and modifications during a contract term), the company's serving process (both collections and O&M), geographic and utility district concentration, and similar details. They will ask for data for both the proposed asset pool as well as the company's overall installed fleet.

Companies that have a portfolio of tax equity investors and back-leveraged financing have a head start on being able to meet these requirements.

Structural issues will need to be addressed both with the rating agencies and in the offering document.

The market has shown that ABS deals can be done around the sponsor share of cash flows in tax equity deals. Securitizations have been done on cash flows in both partnership flip and inverted lease transactions. However, such deals are hard to do if the tax equity investor has the right to sweep cash to cover any tax indemnities that the sponsor owes the tax equity investor. Sponsors have negotiated to cap the percentage of cash that can be swept for this purpose. In at least one deal, the sponsor posted an insurance policy to reduce the likelihood of a cash sweep. The premiums on such insurance range from 2.5% to 4% of the potential payout.

Other securitization structures with tax equity involve a specific agreement with the tax equity investor to subordinate its claims to the securitized debt. In inverted lease tax equity structures, the tax equity lessee has subordinated its potential claims against the lessor to payment of the securitized debt.

At least one potential issuer with a large portfolio of residential solar systems foundered over the inability of the rating agencies to get comfortable with a cash sweep.

Timeline

A solar company doing its first securitization should plan on the transaction taking at least four to six months. The ratings process includes due diligence on the company itself, including its credit profile if the company is not already rated, and on its origination, servicing and O&M operations, as well as asset-specific due diligence. All of this takes time. Structural complications, like securitizing cash flow that has been strained through a tax equity transaction, can add additional time, since the rating agencies will need to understand everything that could block access to the cash flow needed to repay the ABS debt.

For a securitization of an asset type that has not been successfully securitized or where there is less standardization across customer agreements, such as commercial / continued page 6

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In separate news, the Economy Ministry told the Mexican solar photovoltaic trade association, Asolmex, in a ruling in early April that solar panels can be imported without any import duty. The normal duty is 15%. In order to qualify, the project in which the solar panels will be used must be registered under a special program called PROSEC. A solar project should qualify as long as the project company owning the project is a Mexican entity and the project is registered with the Economy Ministry as a power generator before importing the panels.

ARGENTINA is expected to award up to 1,000 megawatts of long-term power contracts in an auction in May.

A new law approved last September requires industrial customers to get up to 8% of their electricity from renewable sources by 2017, 12% by 2019, 16% by 2021 and 20% by 2025. Renewables account currently for only 1.8% of electricity.

Projects in Argentina may be challenging to finance. The country is talking to the World Bank about possible warranties to secure financing. (See related article in this issue starting on page 41.) The government is also expected to provide a 12-month guarantee of payments under power purchase agreements.

TREASURY CASH GRANT litigation carries risk to companies suing for additional payments that the government may ask for money back.

Thirty lawsuits have been filed against the US Treasury by companies that believe they should have been paid more money under the section 1603 program. Companies have up to six years after grants were paid to file suit.

Congress directed the Treasury in early 2009 to pay owners of new renewable energy projects 30% of the "bases" the owners have in such projects in place of tax credits. The tax equity market had shut down. There was concern that development of new renewable energy projects would slow. Congress / continued page 7

Solar Securitizations

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and governmental contracts, the timeline would be longer to accommodate additional due diligence, both by the rating agencies and for the offering document.

One reason that ABS deals take as long as they do is they require preparation of offering documents for so-called 144A offerings. In addition, special disclosures are required such as Rule 15Ga-2 filings of summaries of due diligence reports with the SEC, posting all material documents and making other disclosures (including transcripts or summaries of rating agency discussions) on a Rule 17g-5 website to be available to other nationally-recognized statistical rating organizations who may choose to issue an unsolicited rating.

There may be a hiatus in solar securitizations for part of 2016 until ABS spreads narrow.

The rights to the cash flow being securitized are moved into a special-purpose entity that issues notes that are repaid from cash flows. The notes are generally non-recourse. However, the issuer will be required to make representations that the solar systems and customer agreements in the asset pool meet required eligibility criteria, and it will have to pay indemnities if the representations are breached. The sponsor will be expected to post a guarantee or other credit support to ensure payment.

At least one rating is required. The ratings on the securitized notes should exceed any rating on the solar company. In recent deals, the market has moved to two tranches of debt, an A and a B tranche, in order to increase the total advance rate. Ratings in the securitizations to date have been low investment grade (BBB to A) for the senior tranche of notes and high non-investment grade (BB+ or BB) for the junior tranche. Advance rates against the projected cash flow have been as high as 76% in recent deals. The advance rate is the percentage of the net present value of the share of contracted cash flows the sponsor expects to receive after any tax equity transaction, discounted at an agreed discount rate (typically 6.0%). The advance rates can expect to drift higher over time as this type of paper establishes a longer track record.

FICO scores are used as a basic credit rating tool for residential customers. The weighted average FICO scores in the securitizations to date have been very high: 730 to 760 with no subprime customer agreements.

The customer agreements usually have remaining terms of almost 20 years. However, the tenor of recent securitizations has been much shorter (six to eight years) to achieve a lower interest rate. Rating agencies have so far not given any credit to renewal value of customer agreements beyond the initial 20-year contracted term.

Required debt service coverage ratios have typically been set at 1.25x, below which there is a retention of remaining cash flow on any payment date that would otherwise be distributed to the issuer, and 1.15x, below which all excess cash flow would be applied to pay down the debt.

The A tranche receives a higher rating and lower interest rate than the B tranche, as well as priority in unscheduled principal payments. In certain circumstances, it also has priority over B tranche interest.

The investors for this paper tend to be funds managed by institutional asset managers and institutions like insurance companies.

The best practical advice is to retain accountants, bankers and lawyers with securitization experience and work with those advisors to craft a structure and timeline. Spend the front-end time on asset due diligence and a detailed term sheet of key terms. Be sure the company is ripe for an ABS deal before launching a full process to securitize. ◎

Solar Tax Equity Update

A record number of people — more than 900 — attended a solar finance and investment summit in San Diego in March, reflecting the strong interest among developers and financiers in the solar market after Congress extended a 30% tax credit for US solar projects. Developers have until December 2019 to start construction of projects to qualify for a 30% tax credit. Projects that are under construction in 2020 qualify for a 26% credit. Projects that start construction in 2021 qualify for a 22% credit. The credit drops to 10% after that.

One issue on developers' minds is whether they will be able to convert the tax credits — and accelerated depreciation that is equivalent to roughly another 26% tax credit — into capital in the tax equity market to help finance their projects.

Four tax equity investors and the tax equity head for the largest solar rooftop company did a deep dive into this subject at an annual conference hosted by the Solar Energy Industries Association in New York in late February. The panelists are Albert Luu, vice president for structured finance at SolarCity, Santosh Raikar, managing director for renewable energy investments at State Street Bank, Vicki Dal Santo, executive director for energy investments at JPMorgan Capital Corporation, Dan Siegel, vice president for renewable energy investments at US Bank, and George Revock, managing director and head of alternative energy and project finance at Capital One. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Albert Luu, what new trends are you seeing in the tax equity market?

New Trends

MR. LUU: The ITC extension changes things. Without it, we probably would have been in a position where there is more tax equity than projects. The extension means a lot more projects will make sense. Sponsors will resume the search for tax equity.

MR. MARTIN: Will the extension cause a slowdown in tax equity deal volume this year because people are no longer facing a deadline of year end 2016 to put all remaining solar projects into service?

MR. LUU: I don't know yet. My guess is it will not have much of an impact this year. The other side of the ITC extension is it provides an opportunity for new investors / continued page 8

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directed the Treasury to act essentially as a tax equity investor of last resort. Projects had to be under construction by the end of 2011 to qualify. There were separate deadlines to be put in service depending on the type of project. For example, wind projects had until December 2012 to reach completion. Solar projects have until the end of 2016.

The 30% payments are calculated on project cost. However, many projects are financed in a way that lets the owner use the fair market value of a project rather than the actual construction cost. This has led to disputes with the Treasury about the market value. The Treasury said in a paper posted to its website in June 2011 that a 10% to 20% markup above cost may be appropriate in solar rooftop projects, but the Treasury had backed away from this by 2012.

Of the 30 lawsuits, seven have been withdrawn. Two have been decided. There is also a separate whistleblower suit by a former employee of a development company who believes no grant should have been paid on a project.

In February, the US Court of Federal Claims let the government add a counterclaim asking the owners of six wind farms in California to return $59 million in grant money. The owners sued Treasury in 2013 and early 2014 asking for an aggregate additional grant payment of $200 million. (The separate suits on the six projects have been consolidated.) The government hired an expert witness as part of its investigation of the claims. The expert produced a report in October 2015 that questioned whether three categories of indirect costs should have been included in basis. The National Renewable Energy Laboratory, which reviews grant applications under contract to the Treasury, had asked questions about the three types of costs before grants were paid on the projects. The judge said he would allow the government to reopen the case on these costs, but in an effort to reduce the burden on the owners of revisiting an issue so late in the game of / continued page 9

Tax Equity

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to come into the market. The extension means somewhere between five and seven more years of more than a 10% investment tax credit. That is enough time to make it worthwhile for new investors to spend the time and money to get into this space.

MR. MARTIN: How much tax equity does SolarCity expect to raise this year?

MR. LUU: Last year we did a little more than $1.5 billion. This year, our public guidance in terms of megawatts deployed is 1,250 megawatts, so that translates into somewhere between $1.8 and $2 billion in tax equity that we will need to raise.

MR. MARTIN: Santosh Raikar, what new trends are you seeing in the tax equity market?

MR. RAIKAR: Over the last six months, we have seen a move away from distributed solar into utility-scale projects. For a long time, it was difficult to find good-quality deals among utility-scale projects. That is changing.

Yields are stable.

Apart from SolarCity, we have not seen a lot of sponsors in the residential space looking for the deals.

In terms of deal volume, there is a little bit of a slackening, not due so much to a shift in supply or demand, but because everyone was working hard, and everyone is just taking the foot off the pedal before diving back in. We see some shifting into 2017 of projects that sponsors had planned to complete in 2016.

MR. MARTIN: It seems like people took their feet off the pedal two weeks before the year end, and they have not put them back on yet. Is that your sense as well?

MR. RAIKAR: That's right. I did not hear anything from sponsors until the first week of February or last week of January. Usually you come back after New Year's Day and there is a significant amount of activity. We did not see that this year. We were busy in December locking up letters of intent for execution this quarter. We have a deal closing this week and then another deal closing in March.

MR. MARTIN: Vicki Dal Santo, what new trends are you seeing?

MS. DAL SANTO: It depends on the market segment. We see a little more competition for utility-scale projects and a little more aggressive structuring, maybe longer terms. Tax equity deals have traditionally been structured at six to seven years. We are seeing competition to go out to eight or nine years on those.

There has also been more focus on managing deficit restoration obligations on solar tax equity deals, since the tax equity only contributes about 40% of the fair market value of the projects. With the ITC and depreciation, deficit restoration obligations can get quite high, so there has been more focus on trying to bring those down and make sure that they reverse at an appropriate time.

More solar tax equity investors may be drawn into the market by the tax credit extensions.

MR. MARTIN: How large a DRO will JPMorgan agree to?

MS. DAL SANTO: Definitely facts and circumstances, but probably somewhere in the 30% range.

MR. MARTIN: Thirty percent is historically high.

MS. DAL SANTO: Yes.

MR. MARTIN: The term is the length of time the tax equity investor is expected to take to reach its target yield. From where is the pressure coming to agree to a longer term? There are more tax equity investors. Are the newer entrants pricing to reach yield later?

MS. DAL SANTO: The sponsor usually wants us out of the deal sooner rather than later, since we are not usually the cheapest funding piece in the capital structure. Nevertheless, some sponsors want longer terms, and some tax equity investors are willing

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to go out that far.

MR. MARTIN: Albert Luu, how do you feel about an eight to nine year flip rather than six to seven years?

MR. LUU: For us, it is about optimizing the capital stack, so typically we prefer to have the tax equity flip somewhere in the six-to-seven-year time frame. We would rather monetize cash in the debt markets at more attractive rates.

MR. MARTIN: Dan Siegel, US Bank has a large market share. What new trends are you seeing?

MR. SIEGEL: We are eager to see whether the tax credit extension leads to a lot of new tax equity investors. Most of our focus is on buy-and-hold investments, but we also have an active syndication practice.

A barrier to entry for potential new entrants was simply the fact that the 30% tax credit was about to expire. Giving it a longer life should bring more investors into the space.

With respect to asset type, we have had roughly a 50-50 split historically between distributed and utility-scale solar. That was weighted a little more heavily on the utility-scale side last year because, with the pending expiration of the credit, a lot of large utility-scale projects were looking in 2015 to line up financing before the credit expired.

We will remain active in both market segments. We expect the utility-scale market to remain strong. Projects will get larger and there will be more of them. Tax equity interest in those projects will remain strong. It will be generally a buyer's market in some cases when it comes to competing to supply tax equity.

It is a different story for middle-market commercial and industrial projects. That will remain an underserved space and be more of a seller's market.

MR. MARTIN: What about residential? Is it a buyer's market or a seller's market?

MR. SIEGEL: The larger residential rooftop companies have deep benches of tax equity investors that they work with, so tax equity for them is likely to be more of a buyer's market. It depends on the relative market share of the developer.

MR. MARTIN: You are out actively beating the bushes to syndicate. How many tax equity investors do you think there are currently in the solar sector?

MR. SIEGEL: That's hard to say. The number who are currently active is probably about 15. There are probably 30 to 35 in total when you include investors who have invested in solar at some point in the past. There is room for many multiples of that number.

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which the government was aware when it paid the original grants, he will not let it introduce any new documents or testimony to prove its counterclaim that were not already furnished to the project owners.

The government asked the court for permission in late February to add a counterclaim for $9.2 million against a solar rooftop company that sued for what the solar company said was a $14.5 million underpayment on 4,200 rooftop solar systems. The suit has been pending since February 2013. The government said an expert it hired to review the case advised recently that the company was overpaid.

The government asked the court in early April for permission to revisit whether it should have allowed any part of developer fees paid on two large wind farms to be included in basis. Developer fees of 12.5% and 16% of project cost were paid by the project companies to an affiliate. The Treasury originally allowed fees of 3.8% to 3.9% to be included in basis for each project. However, the government is now questioning whether the developer fees were real. The counterclaims are for a total of $10 million. The initial owners of the projects want the Treasury to pay them an additional $21.9 million.

In other developments, an effort by the owners of 20 utility-scale solar projects in California to get a federal district court to order the Treasury to make full payment of grants on 15 of the projects came to an end with the court telling the solar company in March that the case had to be brought in the Court of Federal Claims. The solar company applied for $614.8 million in grants, but said it had received only $360.5 million. It filed suit in federal district court in July 2015.

The government amended its response in another lawsuit at the end of March involving a biomass power plant to ask the biomass company to return the grant the company was paid on grounds that the biomass plant was taken out of service less than a year after it started operating. The developer originally applied for a grant of $5.47 million. It was paid ***/ continued page 11***

Tax Equity

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Back-Levered Debt

MR. MARTIN: George Revock, what new trends are you seeing?

MR. REVOCK: Most deals today are done on an unlevered basis. However, there is growing interaction between tax equity investors and construction and back-levered lenders. That extensive interaction has not been there in the past. It is becoming a much bigger part of the negotiations in recent deals.

MR. MARTIN: How accommodating are tax equity investors to the needs of the back-levered lenders for predictable cash flow? Where else is there tension?

MR. REVOCK: There is tension around the indemnities that might have to be paid by the sponsor to the tax equity investor and what cash flow can be swept to pay them.

MR. MARTIN: Are there others sources of tension with back-levered lenders: for example, around the level of preferred cash distributions to the sponsor to cover debt service on back-levered debt?

MR. REVOCK: Yes. If a project or portfolio is underperforming, then the tax equity will be delayed in reaching its flip yield and will want an escalating share of cash flow to try to put it back on schedule. The lender will obviously balk at this. There is usually a negotiation about how much of the cash is protected for the lenders versus how much can be shifted to the tax equity investor in the downside case.

MR. MARTIN: Albert Luu, SolarCity has been active in the securitization market. How important is it to avoid cash sweeps to pay indemnities?

MR. LUU: It is important not just to be able to do a securitization, but also for any type of back leverage. The main tension points are around cash sweeps and transfer provisions. The sponsor is usually limited to transferring its interest to a qualified transferee. A back-levered lender will want maximum flexibility to transfer the sponsor interest if it has to step into that interest after a debt default. Those are two areas where we spend a lot of time having discussions with tax equity investors and lenders in an effort to find an acceptable middle ground.

MR. MARTIN: You have been using tax insurance to avoid the need for a cash sweep. Has it worked, and how much does the product cost?

MR. LUU: We used tax insurance for one of our ABS transactions in which we were doing a deal around partnership flips. It was an effort to address a concern from the rating agencies. It is an interesting product in that it can shift the basis risk outside of the partnership transaction. You are essentially swapping the counterparty risk on indemnities from SolarCity to a single A insurer. It is costly. The premiums are somewhere between 2 1/2 to 4%.

MR. MARTIN: Two-and-a-half to 4% of what?

MR. LUU: The policy amount.

MR. MARTIN: The potential payout.

MR. LUU: Yes.

MR. MARTIN: Let me ask the tax equity investors. Has any of you used tax insurance in your deals and, if so, to solve what problem?

MR. RAIKAR: I don't think anyone will acknowledge in public having done so.

MR. MARTIN: Is there anyone less reticent?

MR. RAIKAR: We have not used it.

MR. MARTIN: Let me return to a point that Dan Siegel made. He said some solar market segments are shifting to buyer's markets. Albert Luu, has the market shifted to a point where the negotiating leverage is on your side?

MR. LUU: What the ITC extension did was to allow other market segments to survive. Utility-scale and C&I projects would have been very tough to do with only a 10% ITC. The only market left would have been residential. The larger residential rooftop companies are able to raise capital, but there are always new challenges and the one today that we need to address is the regulatory environment surrounding net metering. That could be a deterrent for some investors. It is a headline risk for some potential new entrants.

MR. MARTIN: Why are C&I projects less likely than residential projects to pencil out without the tax credit?

MR. LUU: The cost structure for C&I is not that much lower than residential, but electricity prices are probably 30% to 40% lower than residential rates. Another problem is it is hard to standardize the customer agreements. Each customer wants to negotiate the contract wording.

Bank Regulatory Issues

MR. MARTIN: George Revock, some bank tax equity investors appear to be wrestling with regulatory issues. What are they?

MR. REVOCK: We are definitely affected by them. There are two issues for us. There is a stress test with the Federal Reserve and, as national bank, we have to get the US Office of the Comptroller of the Currency to sign off on every investment we make.

To date, the OCC has not yet signed off on tax equity investments in residential rooftop solar portfolios, which are essentially retail exposures similar to utility bill receivables. Accordingly, our focus has been on the utility-scale market. Most large financial institutions that make tax equity investments hold them at the holding company, which is not regulated by the OCC but by the Federal Reserve. Unfortunately, Capital One does not have the same ability as some other large financial institutions to invest through our holding company so we end up using our national bank, which requires the OCC to say it does not object.

With respect to the stress test, relying on the ITC for part of our return could be construed as detrimental since Capital One is not profitable under the severe adverse stress scenario. Generally, if a corporation does not pay taxes, then the ITC could generate a deferred tax asset or DTA. DTAs may adversely affect a bank's tier 1 capital. This conclusion is especially unfortunate since Capital One continues to pay billions in federal income taxes each year.

MR. MARTIN: Why is the ITC a deferred tax asset, and why does that then make it harder to meet the tier 1 capital requirements?

MR. REVOCK: Good question. In past stress tests, other business lines have been considered to lose significant sums of money in the severe adverse stress case. These losses, in turn, make our ability to use the ITC in a downside scenario more tenuous.

MR. MARTIN: So you cannot count it as a real asset.

MR. REVOCK: Correct. Without adequate tax capacity, Capital One may be required to write it off for regulatory purposes. It is that potential write off and resultant impact on capital that creates concerns with tier 1 capital.

MR. MARTIN: Are there other bank regulatory issues that are starting to affect the market?

MR. SIEGEL: When banks look at what their annual investment amount may be, they look not just at what the bank's tax capacity is, but also what that capacity is in a stressed environment.

We also see the issues that George Revock mentioned when trying to syndicate deals to other banks. Our banks, and other large banks, invest through a holding company using merchant banking authority. However, a lot of institutions either do not have holding companies or cannot allocate capital through the holding company, so, if they are national */ continued page 12*

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only $316,609 after the Treasury allocated the project cost between the parts of the plant that produce steam and electricity and paid a grant solely on the part allocated to electricity. The project owner filed suit in December 2014 over the shortfall.

The government has won one case and lost one to date. Both decided cases have been appealed. In early February, a US appeals court affirmed the decision for the government in the case it won. The appeals court directed the company that lost the case to pay the government's costs.

GAS-FIRED POWER PLANTS remain able to attract favorable financing.

Opinions differ about whether spreads on debt may widen this year due to higher bank funding costs and limits on lender capacity to take on additional PJM merchant exposure.

Merchant gas plants in ERCOT are trading at steep discounts.

Competitive Power Ventures and GE Energy Financial Services closed in early March on the financing for the 785-megawatt Towantic project in Connecticut at LIBOR plus 300 basis points, according to press reports. The project has a seven-year contract with ISO New England under which it will receive capacity payments. The deal was twice subscribed. It helped that the project is not in PJM where banks are trying to limit their exposure. The developer locked in pricing in 2015.

Clean Energy Futures, Macquarie and Siemens Financial Services closed on the financing for the 800-megawatt Lordstown project in Ohio in early April at 325 basis points over LIBOR, according to news reports. The project connects to PJM and has a five-year revenue put to build a floor under electricity prices. Eight banks participated in the lending syndicate.

NTE Energy closed on the financing for the 475-megwatt Kings Mountain project in North Carolina in late March at ***/ continued page 13***

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banks, they end up having to go through the OCC. To that end, there are some OCC interpretive letters that speak primarily to tax equity deals involving utility-scale projects.

One question for those banks is whether it is safe to rely on an interpretative letter issued to another bank about a specific deal or whether the bank is better served by asking the OCC for permission for its transaction. OCC approval is never certain.

MR. MARTIN: National banks cannot hold interests in real estate. Union Bank early on got an interpretive letter from the OCC that said a partnership flip transaction is not an investment in real estate. Union Bank suggested the transaction was close to a loan in substance. There have been some other interpretive letters since then, including one that walked back part of what the OCC said in the initial letter to Union Bank. Have there been any recent developments about the OCC's view of partnership flip transactions?

MR. SIEGEL: I don't know. When we are working with institutions that have to go through the OCC, they usually try to get the investments qualified as public welfare investments. There are several ways to do that. One way is to show the investments serve low-income populations. Another is to show that they serve a low-to-moderate income area.

Thirty to 35 tax equity investors have invested at some point in solar.

MR. MARTIN: Any other regulatory comments?

MR. REVOCK: Another potential issue is the Volcker rule. Banks have struggled with it, but concluded ultimately that these deals do not fall under that rule.

MR. MARTIN: The Volcker rule prevents banks from engaging in proprietary trading. The tax equity market has concluded that tax equity transactions are usually not covered transactions. It may be important to limit the number of tiers of legal entities.

Next question: we talked a little about the effect of the ITC extension. Santosh Raikar said the extension led to a slowdown in the market at the end of 2015 and the first part of 2016. Albert Luu said more projects will pencil out. Is there anything else that comes from this?

MS. DAL SANTO: Probably more tax equity entering the market. It generally takes a new tax equity investor a year or more to run through the traps within the organization to get approval to make investments. The extension gives institutions time to do that.

Starting Construction

MR. MARTIN: Let's move to another subject. We have now had two rounds of experience with the IRS construction-start rules for the wind industry. The solar industry had experience with similar rules in the more distant past under the Treasury cash grant program.

What lessons do you think people should take away from the experience with these rules to date?

MR. REVOCK: Make sure you talk to reputable tax counsel. Follow the rules and document your compliance with them. You will have to prove to the tax equity investors who ultimately come into the deal that the project qualifies for tax credits.

MR. MARTIN: There are two ways to start construction. A developer can start construction of a project by incurring at least 5% of the project cost or he can start physical work of a significant nature at the project site or at a factory that is making equipment for the project. Will you finance projects that rely on the physical work test as readily as ones that rely on the 5% test?

MR. REVOCK: Yes in concept, but I will be looking to my tax counsel to give me a clean bill of health.

MR. MARTIN: Vicki Dal Santo, you are smiling.

MS. DAL SANTO: Just go into the physical work test with the understanding that tax equity investors will take a conservative view. The 5% safe harbor is an easier route for the tax equity market.

MR. SIEGEL: I agree with what everyone has said. Hire tax counsel and develop a plan. Make sure that tax counsel understands that he or she is going to have to deliver an opinion to the tax equity investor that the project was under construction in time to qualify for a tax credit.

You ran a great article in the most recent NewsWire about practical lessons from the last rounds to start construction. For us, the 5% test is probably a cleaner way to qualify.

If you are relying on physical work, make sure you take notes along the way and document what you are doing. Make sure you understand the scope of the project on which you need to start work. If there is a chance that a certain facility could be treated as two or more separate facilities, then make sure you are starting construction of each separate project.

Depreciation Bonus

MR. MARTIN: Good points. Congress extended a 50% depreciation bonus in December. Congress did more than just extend solar tax credits. Is the depreciation bonus extension expected to help the solar market?

MR. REVOCK: We have not seen it priced into any transactions yet.

MS. DAL SANTO: We have not either.

MR. MARTIN: Santosh Raikar is also shaking his head no. So nobody uses the depreciation bonus?

MR. SIEGEL: I think maybe it eliminates some of the tax capacity on the utility side.

MR. MARTIN: So the utilities disappear as potential sources of tax equity. Other things being equal, less competition on the supply side of the tax equity market tends to push up tax equity yields?

MR. SIEGEL: We do not take it into account in pricing. I will say that.

MR. MARTIN: Albert Luu, has SolarCity managed to get anybody to use the depreciation bonus?

MR. LUU: We have had a few tax equity investors take bonus depreciation. We continue to have those discussions. Our focus is on reaching the flip so that the assets return to SolarCity as early as possible.

We have some tax capacity ourselves, so we would like to take bonus depreciation even if the tax equity investor will not do so.

MR. MARTIN: Has there been an increase in the number of tax equity investors interested in residential solar?

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225 basis points over LIBOR, according to press reports. The output is fully contracted.

Several other gas-fired power projects are being teed up for financing, including the 925-megawatt Westmoreland project in Pennsylvania being developed by Tenaska, the 1,000-megawatt Cricket Valley project in New York being developed by Advanced Power, the 549-megawatt Moundsville project in West Virginia being brought to market by Quantum Utility Generation, and the 1,050-megawatt Fairview project in Pennsylvania being developed by Competitive Power Ventures. The market is also watching the refinancing, currently under negotiation, of the 705-megawatt Newark Energy Center in New Jersey owned by Energy Investors Funds. The initial financing closed in 2014.

Some bankers say spreads on debt have widened by 25 basis points since the start of the year, but others disagree and say they doubt margins will change this year. Bank interest remains strong. Some lenders are reluctant to increase their exposure to merchant gas projects in PJM that have mini-perm structures with refinancing risk.

Meanwhile, Luminant closed in early April on the purchase of two gas-fired power plants in Texas with a combined capacity of 2,998 megawatts for $1.3 billion. The seller was NextEra Energy Resources. The price is roughly $435,000 an installed megawatt, or less than half what it costs to build a new facility. Panda Energy Partners sued ERCOT in late February charging that faulty data on capacity, demand and reserve margins posted to the ERCOT website caused Panda to spend $2.2 billion on three merchant gas-fired power plants that have since lost value after ERCOT revised the data just as the plants were nearing the end of construction. The suit was filed in a state court in Grayson County.

US INVESTMENT TAX CREDIT regulations are unlikely to be updated before 2017.

The Internal Revenue Service is sorting through 25 to 30 comment / continued page 15

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MR. LUU: Yes. There has been a gradual increase where every quarter you have one or two new investors. It takes time to educate them.

It was a lot harder in 2015 to convince an investor to come into this market with the 30% investment tax credit expiring after 2016. We are now circling back to investors with whom we had conversations in 2015 and helping them get through the internal approval process.

MR. MARTIN: Do you just sit at your desk and people call you looking to invest tax equity or are you out beating the bushes to find investors?

MR. LUU: Every once in a while I will get a call, but usually I am on the road knocking on doors.

We have been fortunate to have done deals with everybody on this panel. It is time consuming to do the first deal, but once you create a template in the residential sector, then it is easy to do subsequent deals.

Raising Tax Equity

MR. MARTIN: Let me turn to the tax equity investors. It has always seemed like each of you wants to do business with the same handful of brand-name players and not with companies that are less well known. Is that a fair comment and, if so, how do you decide on the cutoff?

MR. RAIKAR: The sponsor quality matters. There is a limit to the number of deals we can do. There are no criteria per se, but if you find a sponsor who has done business with JPMorgan, then the internal discussions become easier. Having said that, we have done business with some sponsors ahead of JPMorgan.

MR. MARTIN: It seems like the market is flush in tax equity — $13 billion last year in wind and solar — and yet a lot of people trying to raise it have a hard time doing so. Where is the line between companies that can raise tax equity and companies that cannot? Is it the size of the company? The size of the deal pipeline?

MS. DAL SANTO: I don't think there is a bright line. We look at the amount of experience that the sponsor has, how long it has been in the business, and how many projects it has currently operating. We look at the amount of capital it has to backstop indemnities and to give it a buffer to withstand volatility in the business. Another factor is how many dollars we will be able to put out the door in tax equity over a six-month period.

MR. MARTIN: We ran an article in the February *Project Finance NewsWire* called "How to Lose a Banker in 10 Minutes." What are some tips for people about how to lose a tax equity investor?

MS. DAL SANTO: Tell the investor that every customer agreement is separately negotiated and there are 25 different offtakers.

MR. RAIKAR: I will give you an example: what is your after-tax IRR? That question always puts me off.

MR. MARTIN: Why does that annoy you?

MR. RAIKAR: Because it turns on the peculiarities of each deal and the payoff in solar projects is so small.

MR. MARTIN: Are there any other ways to lose a tax equity investor?

MR. SIEGEL: Our tax capacity is a scarce resource. We have a host of sponsors with whom we work regularly, and we have put a lot of time into our documents. It is a turn off to go into a deal with a sponsor who expects us to spend more time on the transaction than he or she has spent. Do your research. Make sure that you have talked to the right people. Have a model built by a reputable firm that understands how the transactions work. Talk to tax counsel.

MR. MARTIN: So be well organized. George Revock?

MR. REVOCK: Good points across the board. Another way to lose a tax equity investor is to approach the market before you have a power contract. If it is not signed, you are merely thinking about it, it is a pipe dream or the utility still has to get the public utility commission to approve it,

Commercial and industrial solar projects remain underserved by tax equity.

then it is premature to be talking to tax equity. The project should be shovel ready when you start talking to us or at least be pretty close to it.

MR. MARTIN: Make sure the project is fully baked. Albert Luu, what issues are coming up in IRS audits?

MR. LUU: We have disclosed that a couple of our funds are under IRS audit. This is to be expected. Our investors are large taxpayers. Some are in the CAP program where their deals are audited in real time.

Basis Per Watt

MR. MARTIN: It seems like the basis risk is the largest risk on the tax side in these deals. Do all of you agree? Vicki Dal Santos is nodding yes.

MR. RAIKAR: Yes

MR. MARTIN: Dan Siegel and George Revock are nodding yes. Tax equity investors, do you have a benchmark price per watt that is a cap on what you are willing to treat as the fair market value of a utility-scale project or rooftop solar system: for example, $3.10, $3.50, $4 a watt for a residential rooftop system?

MS. DAL SANTO: We do not have a firm line, but we certainly take a close look at the appraisal. We make sure it is credible.

We prefer that the appraiser use the cost approach and market comparables. We think the market should be more focused on comparable sales and that appraisers should make more effort to gather such information. We think that the cost and market comps are much more informative than discounted cash flow, which has a lot of subjectivity to it.

MR. MARTIN: So you prefer comparable sales data. How does that work in the residential solar sector?

MS. DAL SANTO: Many sponsors are selling their systems outright to customers, so you could look at the sales prices for a start.

MR. MARTIN: Do you hold them to that direct sales price or do you allow an increment above it because the assets come with tax benefits?

MS. DAL SANTO: We allow an increment.

MR. MARTIN: Dan Siegel, what is the internal discussion at US Bank when you are trying to decide whether you can live with the fair market value proposed?

MR. SIEGEL: We have outside tax counsel on any transaction. Step one is gauging his or her temperature. We do not have any firm ceiling on developer fees, but we have a general sense where they fall typically in the market. Any outlier raises red flags. Similarly, if there is a deferred */ continued page 16*

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letters as it gears up to rewrite its regulations on what part of a solar or other renewable energy project qualifies for an investment tax credit. The existing regulations were written in 1980 and are out of date.

The IRS asked for comments last October in Notice 2015-70.

Many of the letters comment on when batteries and other storage facilities should qualify for a tax credit as part of a project. The US tax code says that an investment credit can be claimed only on the equipment at a project that is used to "generate" electricity.

The IRS has issued three private letter rulings involving batteries. Two were issued to owners of large wind farms that expected to receive or had taken Treasury cash grants in lieu of investment tax credits. One owner was installing a large battery as part of the original construction of the project. Another was adding the battery after the project was already operating. The IRS said that an investment credit could be claimed in both cases. On average, only 3% of the electricity used to charge the battery was expected to come from the grid, as opposed to the wind farm, at one project, and only 15% of the electricity was expected to be from the grid at the other project.

A third private letter ruling confirmed that batteries installed with rooftop solar systems are considered part of the rooftop solar equipment on which an investment tax credit can be claimed, but because the solar company could not represent that the primary use of the battery will be to store the solar electricity as opposed to drawing electricity during off-peak hours from the grid, the IRS said a "75% cliff" applies. As a result, the tax credit is the actual percentage of solar electricity stored during the first year after the battery is put into service. For example, if the electricity used to charge the battery comes 90% from the solar panels and 10% from the grid the first year, then only a 27% investment credit (90% x 30%) can be claimed on the battery. Any dip in that percentage in any of the next four years will lead to full or partial */ continued page 17*

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developer fee, we want to make sure that it is paid within a reasonable amount of time. We pay attention to stacking of fees. In many deals, there are both EPC margins and developer fees, and there is some sensitivity around stacking.

We get appraisals. We have benefited from dealing with a large number of sponsors, particularly in the residential sector. That gives us a pretty good sense about where the fair market values are falling, and we can usually spot ones that are outside the norm.

MR. MARTIN: Do you limit the percentage markup you are willing to accept above cost?

MR. SIEGEL: That is really hard to do because different residential rooftop companies have different business models. There are some residential companies that are purely financing platforms. They acquire projects on a turnkey basis from local installers or channel partners. There are others that are more vertically integrated where one would expect to find various forms of embedded profit along the way.

MR. MARTIN: George Revock, is the discussion at Capital One any different than what Dan Siegel just described?

MR. REVOCK: It is a combination of what Dan and Vicki said. We spend a lot of time looking at the appraisal to make sure the analysis is credible and not at odds with what the same firm or other firms have said about other projects or portfolios. For utility-scale projects, we like to see comparable sales data, and we like to know the facts surrounding each sale so that we can assess the extent to which it is a good indication of value in the project we are considering financing.

MR. MARTIN: If basis risk is the largest tax risk in these deals, then what is the next largest risk?

MS. DAL SANTO: I don't know about tax risk, but another large risk, especially in residential solar deals, is the potential for changes in state policy.

MR. MARTIN: So the possibility that net metering rules will change. Does anyone have a different candidate for the next largest risk?

MR. SIEGEL: I think Vicki is right. The risk of a change in net metering is probably the next biggest risk.

MR. LUU: In terms of tax risk, I would say change in law.

Capital Stack

MR. MARTIN: UBS put out a paper that said tax equity is on average about $1.75 per watt of the capital stack for SolarCity systems. If that is the right number, then what is the total capital stack per watt?

MR. LUU: $1.75 a watt is in the neighborhood for tax equity. You can back into that number from our financial statements. It is roughly 40% of the fair market value of the system. That is typically what tax equity funds.

MR. MARTIN: How much of the capital stack is back-levered debt? UBS suggests it is about 80¢ a watt.

MR. LUU: We raised roughly $2.70 a watt last year.

MR. MARTIN: So the $2.70 must be 95¢ in back-levered debt and $1.75 in tax equity. Does the amount vary if you do a securitization rather than a bank deal?

MR. LUU: I think the advance rates in the two debt markets are roughly the same. They are between 60% and 70%. I think there is a market developing for what we would term cash equity, where you are able to match the long-term stable cash flows under 20-year contracts to investors who want to hold the paper, and they will monetize 100% of the contracted cash flow left over after the tax equity and back-levered lenders take out their shares.

MR. MARTIN: There is speculation in the market that SolarCity and perhaps others, like Sunrun, will sell portfolios as a way of

Deficit restoration obligations in solar partnership flip deals are reaching 30%.

creating a benchmark asset valuation. Is there any truth to the rumors? The speculation is that the discount rate used by the buyers will be somewhere between 7% and 9% for this type of asset.

MR. LUU: Your comment about the speculation is accurate.

MR. MARTIN: The announcement by SunEdison on July 20 last year that it had agreed to buy Vivint not only led to a collapse in SunEdison's share price, but it also pulled down the share prices of all the residential rooftop companies. Has this affected how the tax equity investors view the sector?

MR. REVOCK: The underlying credit at the homeowner level is fine. We started paying more attention to the operating risk, because billing and collections, which are usually contracted out, could involve subsidiaries of these entities.

MR. MARTIN: Let me move to another question. We talked about some of the risks in solar tax equity deals: basis risk, net metering tariff changes, change-in-law risk. Has there been any change in how these risks are allocated between the sponsor and the tax equity investor? [Pause] The answer must be no. What about change-in-law risk? Who takes it in the current market?

MR. LUU: That is a risk that is often shifted back to the sponsor. However, we are starting to see some discussion around a division of change-in-law risks. The main focus by tax equity investors has been on the potential for a reduction in the corporate tax rate and for a scaling back of accelerated depreciation.

MR. MARTIN: Who bears basis risk in the current market?

MR. RAIKAR: That is usually on the sponsor.

MR. MARTIN: Albert Luu, do you agree?

MR. LUU: Yes.

MR. MARTIN: Is that changing?

MR. LUU: We understand there are now some transactions where the basis risk is shared.

MR. RAIKAR: Just to be clear, there is a sponsor indemnifying and potentially providing a parent guaranty to ensure payment of any indemnity. We also need a cash sweep to cover any indemnity, and this is where there is tension between the tax equity investor and the sponsor and, if there is a back-levered lender, with that lender as well.

Solar developers usually don't have as strong balance sheets as wind developers, so the ability to sweep cash is very important.

We like the solar sector, but we need to feel confident there will be enough cash to pay indemnities. In 2015, we did not do any investments in residential solar and we do not foresee any such investments in 2016. A utility-scale / *continued page 18*

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recapture of any unvested tax credit. The solar usage must be at least 75% to qualify for any tax credit, the IRS said.

Many of the comment letters also comment on the 75% cliff. For example, the Solar Energy Industries Association urged the IRS to drop the 75% cliff or, alternatively, to apply a primary use test: as long as the primary use of the battery is to store renewable energy, then the battery qualifies for the full tax credit.

The issues raised by the comment letters, particularly around storage, are complicated. It will take the IRS time to organize a response.

MASTER LIMITED PARTNERSHIP investors may be in for a rude surprise when the MLPs have to restructure debt.

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 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.

Linn Energy, an oil and gas exploration company structured as an MLP, may be on the verge of bankruptcy. The investment units were trading at 32¢ a share as the *NewsWire* went to press.

The company negotiated $1 billion worth of debt relief in November and passed along the income from the cancelled debt to investors on the K-1s each investor was sent for 2015. The K-1s show each investor's share of income at the partnership level.

The company is now offering investors the chance to swap their MLP units for shares in LinnCo, a corporation that manages the MLP and holds a large interest. The swap was offered in late March at the same / *continued page 19*

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project is easier for us to handle.

We closed a utility-scale deal in October where we had to work out a compromise on the cash sweep. It took a while, but once we figured it out, the back-levered lender said it would be happy to staple its financing to any tax equity we sign up in the market.

That gives you a sense of where the tension is and one of the reasons why we have been sticking to utility scale.

Community Solar

MR. MARTIN: Next subject, can community solar projects be financed in the tax equity market?

MR. SIEGEL: I think so. We have been looking at it for a while. We are active in the relatively small community solar market in Colorado. Our bank is headquartered in Minneapolis, so we have an interest in the Minnesota program.

It has been slow to get off the ground, but we think it can be financed. I think some of the challenges are going to be around valuation: what is the proper way to value projects that are utility scale, but that have rotating subscriptions? Sometimes the subscriptions vary depending on the type of subscriber.

There is obviously some execution risk. It is a new market. People need to understand the relative legal positions of the developers and utilities. One of the benefits of community solar is the projects are not on the customer's site. That makes it easier to maintain the asset value after a customer default.

MR. MARTIN: You don't have to rip the panels off the roof.

MR. SIEGEL: You can swap subscribers. That is the theory. We do not know yet how well it will work in practice.

MR. MARTIN: We made a list of risks earlier: net metering, change in law, basis risk. Dan Siegel, you just mentioned another risk for community solar. Is there anything else that should be put on the risk list for community solar?

MS. DAL SANTO: It is closer to the rooftop model in terms of inefficiencies, and that is one concern that we have about community solar. Can you make the deal efficient? How many PPAs are there, are those PPAs standard, can you get a large enough size transaction to make sense to do a deal?

MR. MARTIN: We are at the end of our allotted time. Let's give the audience a chance to ask a couple questions.

MR. HUNTER: Chris Hunter, Brightfield Energy. There was close to $13 billion in tax equity for renewables in 2015. With the five-year extension of the ITC, one could make an argument that we will see a larger volume of high-quality projects in the future. In 2017, 2018 and beyond, we might need $20 billion or more of tax equity a year. In the absence of new entrants, will the 15 or so players who are currently in the market be able to step up to meet that need or might we see a real shortage of tax equity?

MR. MARTIN: Vicki Dal Santo, JPMorgan was about $2 billion of the $13 billion market last year. Do you have room to do more?

MS. DAL SANTO: We have more tax capacity. If there are good deals to be done, we would certainly try to go after them. We are more constrained by resources than tax capacity. There is a limit on the number of deals we can put through our shop at any one time.

MS. CHRISTENSEN: Cynthia Christensen with Namaste Solar. Can you talk about your thoughts on combining tax equity with PACE debt?

MR. SIEGEL: We are looking at a small PACE fund in California. We have not closed it yet. I think it can be done. Part of the challenge with PACE is it is such a quilt work of programs, so when we are working on a particular PACE program, the expertise we gain is only in that particular PACE program. The challenge is the scalability of the model. That is where we are struggling a bit.

MR. MARTIN: Albert Luu, what percentage of the deals you do are inverted leases versus partnership flips?

MR. LUU: We like to be somewhere in the four flips to one inverted lease range.

MR. MARTIN: Why?

MR. LUU: To optimize our tax position. We keep the depreciation in inverted leases.

MR. MARTIN: How many of our tax equity investors are doing inverted leases? Raise your hand. [Pause] We have one: US Bank. George Revock, why is Capital One not doing them?

MR. REVOCK: In an inverted lease, the tax equity ends up being the bottom piece of the capital and, from a credit perspective, that is difficult for us. We would also need to structure the lease to have a longer term than we are willing to consider. ⊚

New US Tax Rules Could Reclassify Debt as Equity

by Keith Martin, in Washington

New regulations the Internal Revenue Service proposed in early April to try to halt corporate inversions could affect all uses of debt between affiliated companies.

The regulations have a potentially very broad reach.

They are merely proposed.

An example of their potential reach is where a foreign company makes an inbound investment into the United States, sets up a US corporation through which to hold the investment, and capitalizes the US corporation partly with debt and partly with equity. This allows the foreign investor to pull out earnings from the US holding company in the form of interest on the debt. Interest is deductible. Use of debt allows part of the earnings to be returned to the foreign investor without US income taxes at the holding company level. The only tax would be a potential withholding tax at the US border.

Most countries allow this type of "earnings stripping." Most countries, including the US, impose limits. The US will not allow part of the interest paid to a foreign parent company to be deducted if the debt-to-equity ratio of the US holding company exceeds 1.5 to 1 and the foreign parent company is in a country with a favorable US tax treaty that waives or reduces US withholding taxes on interest rates.

The new rules give the IRS the means to take a tougher approach to earnings stripping, even when it complies with current US limits.

Another area where the new rules might come into play is in purely domestic contexts where a US company makes a loan to an affiliate. However, they will not affect debt instruments issued between two corporations that join in filing a US consolidated income tax return.

Starting When?

The regulations will affect debt instruments issued after the regulations are republished in final form.

It is not clear how quickly the IRS will move to finalize them.

Some critics are accusing Treasury of resorting to a sledgehammer in its effort to stamp out corporate inversions.

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time the company announced plans to try to restructure its remaining debt. The swap is supposed to shield investors from any further cancellation of debt income, since any such income would be trapped in LinnCo, a corporation. The swap itself is a taxable exchange that could lead to recapture of part of the depletion and depreciation deductions the investors claimed earlier.

Analysts say the potential further cancellation of debt income for investors exceeds the current value of their MLP units by as much as 10 times. The MLP has 350,000 unitholders.

CFIUS reported to Congress in February that foreign companies submitted 147 proposed acquisitions of US companies to it for review in 2014.

A little over a third (52) went into an investigation phase. Twelve proposed deals were withdrawn. One was resubmitted in 2015 with revised terms.

Thirteen of the proposed deals for which foreign buyers sought clearance in 2014 were utility transactions. Of those, seven involved power generation, transmission or distribution, five involved natural gas distribution and one was in the water and sewage sector.

The largest number of filings in 2014 was for in-bound US investments from China. The top five countries for which filings were made in 2014 are China (24) (but China accounted for 30 filings if Hong Kong is added), United Kingdom (21), Canada (15), Japan (10) and Germany (9).

CFIUS — short for the Committee on Foreign Investment in the United States — is an inter-agency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign investments in US companies for national security concerns. Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review.

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Debt v. Equity

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In an inversion, a US corporation with substantial foreign operations inverts its ownership structure to put a foreign parent company on top with the aim of keeping future earnings from its overseas businesses outside the US tax net. An inversion is more attractive if the new foreign parent can also drain earnings from the US subsidiary through earnings stripping.

The Treasury looked for ways to limit the new rules to inversion situations. It is hard to do. The mere threat that the regulations may be published in final form before a complicated inversion that is costly to implement can be completed may be enough.

The broad reach of the proposed regulation would affect lots of inbound US investment.

New IRS rules intended to stop corporate inversions could hit foreign companies making investments in the United States.

The Treasury turned to issuing regulations after Congress made clear it has little interest in acting. Republicans control both houses of Congress. Republican leaders believe the way to fight inversions is to reduce the corporate income tax rate and believe that narrowly-targeted measures will ultimately prove ineffective. Edward Kleinbard, a law professor at the University of Southern California and former staff chief of the Joint Committee on Taxation, put it differently: "Congress has shown itself unwilling to honor its obligation to invest in the routine maintenance of the tax code . . . ."

Documentation

The proposed new rules have three parts.

First, they require any company issuing debt to an affiliate to keep written documentation to prove the instrument is debt. The IRS will need this to do its own analysis.

The documentation must prove four things. The instrument is a legally-binding obligation to pay a fixed sum of money on demand or on one or more fixed dates. The affiliated lender has a right to enforce the obligation, including a right to declare a default and accelerate repayment, and it has claim to company assets in a liquidation to satisfy the debt that is superior to any claim that the shareholders have to the assets. Repayment is expected by the maturity date. The parties behave in fact over time like a borrower and an arm's-length lender.

The documentation must be contemporaneous. Thus, with some exceptions, all but the information relating to actual performance must be compiled within 30 days after the debt instrument is issued. The information must be kept on file for the full period the debt is outstanding plus any additional period until the statute of limitations has expired on a back tax claim.

The documentation must include "complete and (if relevant) executed copies of all instruments, agreements and other documents evidencing the material rights and obligations of other parties such as guarantees and subordination agreements." Proof that repayment is expected may require cash flow projections given to third parties, financial statements, business forecasts, asset appraisals and debt-equity and other financial ratios and information about sources of cash for repayment.

Such extensive documentation is burdensome to assemble. Therefore, the IRS is only requiring it where any member of the expanded affiliated group has shares that are publicly traded, or the group had more than $100 million in assets or revenue of more than $50 million a year in any of the three prior years.

The documentation is "necessary, but not sufficient" to ensure treatment of the instrument as debt. The IRS remains free to treat a purported debt as equity on substantive grounds.

Two companies will be considered affiliated, so that documentation will be required to validate debt instruments between them, if the companies have at least 80% common ownership by vote or value. It is the same test as for determining whether two corporations can join in filing a US consolidated income tax return, except that foreign corporations are considered part of the affiliated group as are corporations with partnerships in between them. The IRS suggested debt of affiliated partnerships and disregarded entities may also be reclassified under these rules. It is not clear why since these types of entities do not pay income taxes and are not obvious candidates for earnings stripping. The earnings stripped would have to belong to a corporate partner or owner. It is also not clear what metrics will apply to controlled partnerships to treat them as affiliated.

Not Debt

The new proposed rules put companies on notice that the IRS may take action during an audit to treat a debt as part debt and part equity. An example is where the IRS believes that only part of the "debt" is likely to be repaid.

While there have been instances where the IRS or the courts have taken that position in the past, such instances have been rare.

Debts between a broader group of companies may be picked up by this part of the new rules. Two companies will be considered affiliated for this purpose if they have only 50% common ownership by vote or value.

The focus is on instruments that the parties characterize at time of issuance as debt. The agency does not plan to invoke these new powers to recharacterize instruments as debt that the parties start out treating as equity as that "would require more detailed guidance."

Finally, the proposed rules curb transactions that increase related-party debt without financing any new investment in the United States.

They identify six transactions that the IRS believes are usually undertaken for tax reasons and rarely have a real business purpose. The common thread in the transactions is debt is issued to a related party without receipt of any actual cash.

An example is where a US subsidiary corporation pays a dividend to its parent by issuing the parent a debt instrument. No new investment is made in the parent. In a cross-border context, this gives the foreign parent greater ability to strip earnings.

The same strategy could be used by a US parent company to repatriate earnings from an offshore subsidiary to the US without a US tax on the earnings. For example, the foreign subsidiary could issue debt — essentially an IOU — to its US parent in a year when the foreign subsidiary has no undistributed earnings and the US parent has enough basis in its stock in the subsidiary to treat the distributed debt instrument as a / continued page 22

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Review takes 30 days. Transactions that raise potential issues then move into an investigation phase that takes another 45 days.

The report lists as potential areas of concern investments in US companies that have access to classified or sensitive US government information and acquisitions by foreign companies that are controlled by a foreign government, especially where the foreign country has a poor record on nuclear non-proliferation or other national security matters or the country has a coordinated strategy of trying to acquire critical US technologies. Concerns are also present in acquisitions of projects with offtake contracts with federal, state or local government agencies that have functions related to national security, and projects that "involve various aspects of energy production, including extraction, generation, transmission, and distribution" or that are near US military bases or other sensitive US government facilities.

The committee makes recommendations. The President has ultimate authority to block a transaction.

Presidential action to block a transaction is rare. President Obama ordered Chinese-backed Ralls Corp. in 2012 to divest four wind farms that the company bought in Oregon at which it hoped to deploy turbines made by its affiliate, Sany Electric Co. One of the wind farms is close to a US Navy base that provides training for drone aircraft.

Most transactions that raise problems are voluntarily withdrawn. Many are later resubmitted on revised terms. In some cases, transactions are approved after the acquirer agrees to mitigation measures.

CFIUS reports annually to Congress. According to the latest report, covering the period through December 2014, the committee reviewed 627 proposed transactions in the six years from 2009 through 2014, or an average of 105 a year. About 11% of proposed transactions were withdrawn during this six-year period, with 3% of withdrawals occurring during the initial review stage and another / continued page 23

Debt v. Equity

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return of capital. In a later year when the subsidiary has earnings, it can use them to repay the debt. The earnings end up not being taxed in the United States.

The IRS said it plans to treat the debt issued in these cases as equity. The key is there is a parent-subsidiary relationship — either inbound or outbound — there is no new capital investment by the parent, and there is no real business purpose. Although the holder of the debt instrument may have different legal rights than a equity participant in theory, the IRS said, those differences have little meaning when the parties are related. ◎

Fund Managers Take Note

by Keith Martin, in Washington

Private equity funds that engage in active management of portfolio companies are troubled by the decision in a lawsuit involving Sun Capital Partners.

The decision is troubling on two levels.

First, two private equity funds were held liable for shortfalls in pension plan contributions by a portfolio company that the two funds owned.

Second, the portfolio company was a corporation and the two funds were shareholders, but the courts treated the funds as if they were engaged directly in the "trade or business" of the portfolio company based on the logic in a US Supreme Court decision in an income tax case. This could have tax implications.

Look Through

Two investment funds managed by Sun Capital Advisors bought a company, Scott Brass, Inc., that made high-quality brass, copper and other metals. The funds purchased the company in 2007 for $7.8 million.

Sun Capital describes the business of the funds it manages as buying underperforming but market-leading companies at below intrinsic value with the aim of turning them around and then selling them for a profit.

Scott Brass made contributions to a Teamsters pension fund under a collective bargaining agreement. Sun Capital employees were heavily involved in the business after the acquisition. However, falling copper prices in the fall 2008 reduced the value of the Scott Brass inventory, and the company was forced into bankruptcy in November 2008. Scott Brass had stopped making contributions to the pension fund shortly before the bankruptcy. There had been some underfunding of pension benefits even before the Sun funds bought the company.

After the bankruptcy, the Teamsters pension fund sent a demand for $4.5 million in withdrawal liability to Scott Brass and Sun Capital.

It claimed that the two Sun Capital investment funds and Scott Brass were under common control and, therefore, were jointly and severally liable for the withdrawal liability for the underfunding.

The Multiemployer Pension Plan Amendments Act of 1980 allows the US government to recoup unfunded pension liabilities in union, multi-employer plans. Any employer withdrawing from a plan must pay its proportionate share of the plan's vested but unfunded benefits. The Act treats all trades or businesses under common control as a single employer of workers who work in any of the businesses. However, two conditions must be satisfied to impose liability on an entity for underfunding in a pension plan. The entity must be under common control with the company employing the union workers, meaning at least 80% common ownership, and the entity must be a "trade or business."

US taxpayers would have had to pick up the underfunding through the US Pension Benefit Guaranty Corporation if the Sun funds were found not liable.

The Sun funds owned 100% of the shares in Scott Brass. One fund held 70% and the other fund held 30%.

A US appeals court found the fund with the 70% interest liable for its share of the underfunding in 2013, but sent the case back to a federal district court to assess whether the fund with the 30% interest should also be held liable. (For earlier coverage, see the October 2013 *NewsWire* starting on page 21.) The district court said yes in late March.

The case is *Sun Capital Partners III, LP v. New England Teamsters & Trucking Industry Pension Fund*.

Investment Plus

The two funds had different sets of investors, although there was some overlap. Sun Capital admitted that an important consideration in splitting ownership of Scott Brass in a 70-30 ratio between the two funds was to try to avoid having either fund reach the 80% threshold that would have made Scott Brass under common control with the fund holding the 80% interest. PBGC regulations say common control is 80%.

Private equity funds are troubled by a recent court decision.

The district court said the economic reality is there was common control. Many private equity funds use parallel fund structures in which an onshore fund for taxable investors and an offshore fund for US tax-exempt and foreign investors invest alongside one another. The court said it would treat parallel funds as under common control and, although the funds in this case were not parallel funds since they had only some investments in common, the two funds had effectively formed a partnership to invest in Scott Brass. They were not two separate funds choosing the level of ownership interest each wanted to hold independently and making independent decisions about the Scott Brass business. They were under common management, and the management company supplied two of the three Scott Brass directors.

The court said the partnership of the two funds was engaged directly in the Scott Brass trade or business because of its active management of that company.

The earlier decision in the case by the US appeals court in 2013 led to considerable hand wringing among tax lawyers about the possible broader tax implications.

Among the potential implications are the possibility that income earned by fund managers from portfolio companies they actively manage will be treated as ordinary income rather than investment returns. Foreign investors who */ continued page 24*

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8% during the investigation stage.

In 2014, only 8.2% of transactions were withdrawn. Another 6.1% were cleared, but after agreeing to mitigation measures.

Congress asked CFIUS to note any transactions involving foreign companies in countries that comply with the Arab boycott of Israel. Eight such transactions were identified in 2014, mostly involving the energy sector. The foreign companies making US acquisitions were in the United Arab Emirates, Qatar, Saudi Arabia, Bahrain and Oman.

INDIA continues trying to collect taxes from foreigners holding investments in India through offshore holding companies when shares in the offshore companies are transferred or sold.

The country has been locked in a long-running dispute with Vodafone, which India says owes at least $2.1 billion in capital gains taxes that were triggered when the telephone company bought a 52% interest in an Indian mobile phone business, plus options to take its interest to 67%, from Hong Kong-based Hutchison Whampoa for $11.2 billion in 2007.

Vodafone bought a Cayman Islands subsidiary of Hutchison Whampoa that owned an interest in a mobile phone company in India through several tiers of Mauritius companies.

Vodafone said that even if a tax was triggered by the sale, it bought the shares, and the seller — not Vodafone — should be taxed on the gain. However, Indian law requires a buyer to withhold tax from the purchase price where the seller is outside the Indian tax net.

The Indian Supreme Court ruled in 2012 that the share transfer was not subject to tax in India.

The Indian government then put a bill through parliament to impose such taxes retroactively on offshore share transfers back to April 1962. However, there is a six-year statute of limitations on back tax claims.

Vodafone asked the International Court of Justice in The Hague in May 2014 to commence an arbitration under */ continued page 25*

Fund Managers

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set up US entities treated as corporations to hold inbound US investments that they actively manage could be considered engaged in US trades or businesses and forced to file US tax returns, causing them to lose protections under US tax treaties that reduce or eliminate US withholding taxes on dividends and interest the foreign investors receive from US sources. Tax-exempt investors could have to pay taxes on corporate dividends received through funds as "unrelated business taxable income."

However, there has been less public comment after the latest decision. It may be that the decisions, while a warning, will end up holding no larger lesson than that private equity funds should think twice about investing in portfolio companies that have underfunded union pension plans.

Net Metering in Play in Multiple US States

by Megan Strand and Ana Vucetic, in Washington

Adjustments to standard net energy metering policies are possible in eight, and likely in another two, US states during the remainder of 2016.

Net metering programs, which have been adopted in 45 states plus the District of Columbia and three US territories, have played a key role in the rapid growth of US rooftop and other forms of distributed solar. Residential solar installations increased 66% in 2015 over the year before. Such development has generally been opposed by local electric utilities since distributed solar disrupts the traditional business model by reducing the amount of power purchased from the grid. Net metering requires utilities to compensate customers for any excess generation, usually at retail rates. The programs are called net metering because the customer utility meter effectively runs backwards.

The utilities have succeeded in scaling back net metering benefits in three states. Net metering programs in Arizona, Hawaii and Nevada have been revised, including by reducing the amount paid for excess electricity and imposing fixed monthly charges or other new charges on customers to help maintain the grid. In contrast, the California Public Utilities Commission reaffirmed the current net metering framework and adopted a similar successor tariff. However, California will revisit the successor tariff in 2019.

Another 13 US states have either recently enacted or proposed new or revised net metering rules. (This number includes the 10 states in which action is possible or likely later this year.) A number of the proposed rule changes favor rooftop solar.

Background: Hawaii, Nevada, California

The first generation of net metering programs — as opposed to variations such as virtual net metering or community solar — credited customers at the full retail value for any excess electricity exported to the grid against the amount of electricity drawn by the customer from the grid when its energy usage exceeds its on-site system output. Essentially, a utility customer is billed for its "net" energy use. This paradigm is shifting.

The Hawaii Public Utilities Commission decided last October, in Order No. 33258, to close the net energy metering program of three HECO Companies utilities to new participants. The commission approved two alternatives: a self-supply option or a grid-supply option. It also instructed the utilities to bring back to the commission a third, time-of-use option for customers. Unlike what happened in Nevada, existing net metering customers and those who applied to participate in the program by the date of the commission order remain eligible for the prior program.

Under the "grid-supply option," customers can receive credits for energy exported to the grid that offset monthly utility energy charges. The credit is a fixed rate reflecting the 12-month average on-peak avoided cost for the relevant island grid, ranging from approximately 15¢ a KWh to 28¢ a KWh depending on the utility service territory. The credit amount will be fixed for a period of two years. Aggregate participation in the net metering program is capped initially at 25 megawatts for customers on Oahu and at five megawatts for customers in each of the Maui Electric Company and Hawaii Electric Light Company service territories. Any monthly generation in excess of the customer's utility bill is not credited or carried over to a future month.

The self-supply option is designed for customers who intend to use all their own electricity without exporting any to the grid.

Under both options, residential customers will be required to pay a minimum bill of $25 a month, and small commercial customers will have to pay a minimum of $50 a month, to help maintain the grid. A lawsuit filed by solar advocates in state court last October, challenging the order on procedural grounds, was dismissed in January.

In Nevada, the Public Utilities Commission approved, in late December 2015 in docket Nos. 15-07041 and 15-07042, a successor tariff that overhauls the existing net metering structure for customers of NV Energy and its two utility subsidiaries, Nevada Power Company and Sierra Pacific Power Company. This new tariff increases monthly basic service charges, reduces solar export compensation by replacing retail rates with an avoided energy cost rate structure and establishes a separate rate class for residential and small commercial systems and a time-of-use pricing mechanic for net metering customers.

The commission reaffirmed the revised net metering tariff in mid-February and retained a controversial provision applying the new requirements to the approximately 17,000 existing net metering customers, but with a 12-year transition period to implement the revised rate structure fully under the new tariff.

During the transition, the basic service charge increases for net metering customers every three years (by NV Energy's estimates, from $12.75 a month to $38.51 by 2028 for residential systems located in certain service areas), with a corresponding decrease in export compensation to customers.

In response, major solar developers have exited the Nevada market and the debate has moved to the state courts. In January, net metering customers filed a class action lawsuit against the Nevada Power Company alleging various tort claims and deceptive practices, and solar industry group The Alliance for Solar Choice (TASC) filed suit in mid-March against the Public Utilities Commission in an effort to overturn its decision. A proposed referendum backed by the solar industry aimed at restoring the prior net metering rate regime has been challenged in state court by utility interest groups. Meanwhile, Tesla is reportedly backing a ballot initiative aimed at opening the electricity market and overturning the retail sales monopoly enjoyed by the Nevada utilities.

In contrast, the California Public Utilities Commission adopted a successor net metering tariff — called "NEM 2.0" — by a 3-2 decision in late January that favors the solar rooftop companies. The docket is No. R14-07-002. The new tariff generally retains the existing net metering structure that links customer compensation to retail rather than wholesale rates through 2019, but with certain modifications. The modifications involve certain time-of-use rate requirements, an interconnection fee and a requirement that customers pay all specified non-bypassable charges for electricity imported from the grid. (Non-bypassable charges are utility charges that appear on a customer's bill, even if it buys its electricity from another supplier.) The revised tariff */ continued page 24*

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the bilateral investment treaty between India and Holland, where the Vodafone subsidiary that bought the shares is located. An issue in the arbitration is whether the bilateral investment treaty can be used in connection with tax disputes. Both sides appointed arbitrators, but the two party-appointed arbitrators could not agree on a third, neutral arbitrator. Vodafone asked the court in March to name one.

The Indian government renewed its demand that Vodafone pay the taxes in a letter to the company in February.

Meanwhile, the Indian government included a one-time settlement offer for all companies that made indirect share transfers in its latest budget message to parliament. The offer is the government will not ask for penalties and interest if the companies pay the underlying taxes on the share transfers.

Cairn Energy PLC, an independent oil and gas exploration company, initiated international arbitration proceedings in January with India to resolve a dispute over a $1.6 billion tax assessment purportedly triggered by a share transfer as part of an internal reorganization in 2006.

Separately, Kawasaki Heavy Industries won a favorable decision before a tax tribunal in India over whether a liaison office it established in India created a "permanent establishment" for the Japanese parent company in India, thereby subjecting the parent company's profits on all Kawasaki equipment sales in India to tax in that country. Japan and India have a tax treaty that is supposed to prevent India from collecting income taxes on income that Japanese companies earn outside India on sales to Indian customers unless the seller has a permanent establishment in India that helped make the sale.

The tax tribunal said that a mere liaison office does not create a permanent establishment. The office operated under a limited power of attorney that made clear the liaison office could not bind the parent company and was only to be involved in preparatory activities. When the Reserve Bank of India ***/ continued page 27***

Net Metering

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applies starting July 1, 2017 to new net metering customers of the three largest investor-owned utilities in California: San Diego Gas & Electric, Southern California Edison and Pacific Gas & Electric. However, such requirements may take effect sooner if certain megawatt thresholds are reached under a utility's net metering program (for example, when total net metering capacity reaches 5% of aggregate customer peak demand for the utility).

In early March, each of the three utilities asked the commission to reconsider the decision. The requests are pending.

Mississippi, Pennsylvania and Virginia

The Mississippi Public Service Commission voted 3-0 in December to put a new net metering program in place in that state. The decision is in docket No. 2011-AD-2.

The commission directed utilities to value and credit excess energy generated by customers into the grid on a monthly basis, with unlimited carryover of bill credits.

The credit amount is a compromise between the local utilities and the solar industry. Excess energy is not credited at the full retail rate (approximately 10¢ a KWh), but rather at the wholesale rate, plus a temporary adder of 2.5¢ a KWh leading to a rate of approximately 7¢ to 7.5¢ a KWh, depending on the utility service territory.

The temporary adder is recognition of the unquantifiable benefits of net metering, such as increased generating capacity. The adder will be replaced within three years by a value reflecting the "actual benefits" of distributed generation, as determined by an independent consultant study. Local investor-owned utilities must offer an additional adder of 2¢ a KWh to the first 1,000 qualifying low-income customers, for the first 15 years of service, in an effort to deal with the distributional effects of net metering. The program could leave grid costs being disproportionately borne by customers unable to install solar panels.

The rules limit the size of residential installations to 20 kilowatts. Participation in each utility's program is capped at 3% of the total distribution system peak demand. Several requests for clarification (from interest groups such as the Sierra Club, who otherwise notes general support for the rules, and TASC) and for rehearing (from electric power associations) have followed. To date, the Mississippi Public Service Commission has taken no action on such petitions, and it is not expected to do so.

The Pennsylvania Public Utility Commission voted 3-2 in mid-February to retain net metering at the full retail rate of approximately 8¢ a KWh, while amending certain other net metering provisions. The commission action can be found in docket No. L-2014-2404361.

The commission reaffirmed statutory restrictions on nameplate capacity of residential systems at no larger than 50 kilowatts and on non-residential systems at no larger than three megawatts.

It added a new requirement that any system participating in net metering cannot be sized to generate more than 200% of the utility customer's historic annual electric consumption. This percentage is significantly higher than the percentage originally proposed by the commission in February 2014. No applications for rehearing had been filed with the commission as of the end of March. The new rules now pass to the Pennsylvania Independent Regulatory Review Commission for review, which has scheduled a public hearing in mid-May on the changes.

Virginia revised its net metering rules in November.

The Virginia State Corporation Commission issued an order approving updated rules that double the system capacity limit for nonresidential customers

Ten states could revise their net metering policies this year.

from 500 kilowatts to one megawatt. The order also limits the capacity of any facility installed after July 1, 2015 to the expected annual energy consumption of the customer based on the previous 12 months of billing. It also requires new net metering customers to notify and get approval first from the local utility. The Virginia order is in case No. PUE-2015-00057.

No immediate action on the legislative front seems likely as proposed bills addressing net metering in both houses of the Virginia legislature have been tabled until 2017.

Currently in Play

Local utilities in Arizona are continuing to try to reduce customer compensation for exported power and increase monthly fees.

The Arizona Corporation Commission authorized the Arizona Public Service Company in late 2013 to assess a fixed charge on distributed generation systems in response to concerns that the burden of maintaining the grid was being shifted to customers without solar on their roofs.

Tucson Electric Power Company and UNS Electric, both owned by Fortis, have requests pending before the commission to follow the same path as Arizona Public Service to revise rate structures. The requests are in docket Nos. E-01933A-15-0322 and E-04204A-15-0142.

Ohio is another current battleground.

AEP Ohio has a lawsuit pending before the Ohio Supreme Court to have the amount it is required to credit net metering customers declared unlawful. The case is 2014-1290. It has been on hold, after both sides asked for a joint stay, to give the Ohio Public Utilities Commission a chance to revise its own rules.

The commission proposed new net metering rules in November 2014. The new rules allow utilities to offer net metering contracts on terms determined by the parties to the contract, including compensation at the "utility's standard offer rate." The rules stipulate that excess credits can be carried forward for up to 36 months. They also limit system size to 120% of customer load, calculated using the average amount of electricity supplied by the utility to the customer annually over the previous three years.

Solar interest groups such as TASC have filed comments in support of the rules, but local utilities, including AEP Ohio, are opposed. The docket is No. 12-2050-EL-ORD.

Regulatory bodies in other states, such as Illinois and Louisiana, are working to revise existing net metering programs including by capping total participation.

The Illinois Commerce Commission proposed new net metering rules in April 2015. The rules are part of / *continued page 28*

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granted Kawasaki permission to open the liaison office, it said, "except for the proposed liaison work, the office in India will not undertake any other activity of a trading, commercial or industrial nature, nor shall it enter into any business contracts in its own name without prior permission."

There was no evidence the liaison office was involved in any of the sales that the tax assessor wanted to attribute to it.

The Delhi Income Tax Appellate Tribunal rendered a decision in the case in February. The case is *Kawasaki Heavy Industries Ltd. v. ACIT*.

US SOLAR COMPANIES are expected to install 16,000 megawatts of solar panels in 2016, up from 7,300 megawatts in 2015, according to a Solar Energy Industries Association report in March.

SEIA expects solar output to increase from 1% of US electricity supply today to as much as 3.5% by 2020. The cost of panels has dropped 67% since 2010. Utility-scale projects will account for roughly 75% of new solar installations in 2015. Residential installations are expected to be 2,800 megawatts this year, up from 2,100 megawatts in 2015.

Rooftop solar could eventually supply as much as 40% of US electricity, according to a National Renewable Energy Laboratory report in late March. NREL looked at the rooftop potential in 128 urban areas. It redid calculations that it had done in 2008. The potential almost doubled since then due to more efficient solar panels, better solar simulation tools and new construction of more rooftops in areas with good sunlight and few trees.

US ELECTRICITY DEMAND fell 1.1% last year, the fifth decline in the last eight years.

FORTY-ONE COAL-FIRED POWER PLANTS with a generating capacity of 5,600 megawatts are expected to be retired in / *continued page 29*

Net Metering

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docket No. 15-0273.

The commission wants to increase the net metering enrollment cap to 5% of utility load and base compensation rates on whether a customer is considered "competitive." Residential customers are not considered "competitive," so they would continue to receive credit at retail rates unless they contract otherwise with the utility.

The commission sent a second notice about the rulemaking to the administrative rules committee of the state general assembly in November. The new rules will be adopted if there are no objections from the committee. At least two utilities — Commonwealth Edison and Ameren — want changes.

The Louisiana Public Service Commission initiated a two-phase rulemaking in December that would reduce bill credits for customers after a utility reaches a net metering cap.

Two local utilities — Entergy Louisiana and Southwestern Electric Power — have already reached their caps. The Louisiana commission proposed that once a utility reaches 0.5% of its monthly retail peak load, any excess energy exported to the grid by net metered customers would be credited at the avoided cost rate.

Existing customers would not be grandfathered.

A recommendation on grandfathering is expected from commission staff, but none was issued as of the end of March.

A number of states in the northeastern US are also reconsidering their net metering rules.

The Maine state legislature directed the state Public Utility Commission in July 2015 to convene a stakeholder group to suggest an alternative to net metering.

Under a bill pending in the state legislature — LD 1649 — new residential and small business customers installing distributed generation systems of up to 250 kilowatts in size would enter into long-term contracts with the local utility for net metering. The Maine Public Utilities Commission would set the rates to be paid under such contracts. The rates would decline as the total level of residential and small business capacity approaches certain statewide capacity targets.

Existing net metering customers in Maine would remain eligible for compensation under the current tariff for 12 years.

The bill would direct the commission to adopt implementing rules by the end of 2016.

A public hearing was held in the legislature on March 16. The bill is expected to be reported out of committee once certain amendments, not yet available as of publication, are incorporated. Some modified version of the bill seems likely to pass, although the current legislative session will end on April 20. Whether the governor will sign it is a separate question: he opposes it.

In Rhode Island, the state legislature directed the Rhode Island Public Utilities Commission in January 2015 to open a docket to consider rate design and distribution cost allocation among rate classes. The legislation directed the commission to issue an order by March 2016, with any new rates to take effect in April. No such order on rate design or cost allocation had been issued as the NewsWire went to press.

In New York, the Public Service Commission temporarily suspended the state's net metering caps (currently 6% of each utility's 2005 load). The commission has a REV proceeding — "Reforming the Energy Vision" — underway in part to address net metering issues. Utilities have been instructed to continue accepting interconnection applications for from solar customers who want net metering until the policy is addressed in the REV proceeding. The commission asked in December for comments on an interim successor to the existing net metering program. The request for comments is in Case 15-E-0751. Comments are due in April.

The Vermont legislature directed the Vermont Public Service Board to convene workshops to design revised net metering rules.

The most recent draft rules as of March 2016 would compensate new net metering customers at a "blended residential rate" that is either the retail rate or an average of the retail rates for utilities that charge progressively higher rates as consumption increases. The draft rules also allow utilities to charge net metering customers a "reasonable" fee to cover certain fixed costs. Bill credits may be carried forward for up to 12 months and current customers would be grandfathered into their existing rates for 20 years.

The draft rules are silent on an aggregate cap for net metering participants. Public hearings on the draft rules are scheduled for early May.

Local utility Green Mountain Power reached its statutory cap in early November 2015, and petitioned the Vermont Public Service Board for permission to offer net metering above this cap. The board is not reviewing any applications currently for

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projects above 15 kilowatts that submitted interconnection requests to Green Mountain Power after the cap was reached. It asked the utility for more information in March.

Massachusetts and New Hampshire

The net metering debates in the states discussed earlier balance two competing interests: solar rooftop customers and solar companies who want to preserve bill credits at retail rates and avoid monthly back-up service fees and utilities who want to pay less for customer-generated electricity and charge monthly fees from all customers to ensure the cost of maintaining the grid is equitably borne.

While definitive action on net metering revisions in these states is difficult to predict, two other states are moving quickly to revise their rules.

Some of the proposed changes favor rooftop solar.

Massachusetts acted as the *NewsWire* was going to press. The state legislature voted to increase the net metering cap by 3% and to reduce payments to large privately-owned systems above 25 kilowatts feeding excess power into the grid once the new cap is reached. Utilities are permitted to impose a minimum monthly fee on customers to help pay for the grid. Customers who qualify for net metering before the cap is reached would be grandfathered for 25 years. The Republican governor is expected to sign the bill.

The new cap on net metering participation is expected to be reached quickly. Massachusetts has raised the cap four times in the last six years.

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2016 in the United States, according to the US Energy Information Administration.

WHOLESALE ELECTRICITY PRICES were up 2.6% across the United States and Canada in 2015.

The largest increases were a 10.9% increase in Florida and a 10.2% increase in WECC excluding California. (WECC is the western US states and the two western-most Canadian provinces along the US border.) The largest reductions were an 8.0% drop in NBSO and a 7.6% drop in ISO-New England. (NBSO is New Brunswick, Nova Scotia and parts of northern Maine).

The renewable energy tax credit extensions in the United States last December are causing wind and solar companies to dive back into development. This, and the wide gap between the expected number of coal retirements compared to the amount of expected new solar capacity additions, are expected to put downward pressure on wholesale power prices.

GREENHOUSE GAS EMISSIONS remained flat globally for the second year in a row in 2015, according to the International Energy Agency. Emissions are decoupling from economic growth. They remained flat during a period when the global economy grew 3%. Renewables accounted for around 90% of new electricity generation worldwide in 2015.

The United States saw its greenhouse gas emissions drop by 2% in 2015.

OREGON moved to phase out use of coal for generating electricity and to increase the share of electricity that comes from renewable energy.

The effort to bar use of coal may land in court.

Oregon Governor Kate Brown signed a bill in March that bars the two major utilities, Pacific Power and Portland General Electric, from supplying any electricity from coal starting in 2030. Portland General can keep an existing coal-fired power plant in Montana until 2035. The two utilities supply about 70% of Oregon electricity.

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Net Metering

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Facilities installed after Massachusetts reaches capacity would be credited at the wholesale rate, a difference of approximately 12¢ to 14¢ a KWh.

The issue of caps on installed net metering capacity has also arisen in New Hampshire.

In response to local utilities reaching or nearing statutory caps on net-metered systems of all sizes, the New Hampshire Public Utilities Commission issued an order in docket No. DE 15-271 in late March directing utilities to implement new customer-generator interconnection and net metering queue management procedures. The new procedures (including certain revised application requirements and project milestones) apply to both proposed and existing projects, giving the latter 30 days to demonstrate compliance with the new requirements once the procedures are implemented. No reconsideration period is provided for and no comments had been filed as of the end of March responding to the decision.

Meanwhile, efforts to increase the state-wide 50-megawatt cap on net-metered facilities have gained widespread support before the state legislature. SB 333, which passed the Senate in February 2016, would raise the cap to 75 megawatts, while HB 1116 would raise the cap to 100 megawatts. The House bill passed the full House in March and is expected to pass the full Senate in early April. The New Hampshire governor issued a statement strongly in support of lifting the cap. ⊚

Stronger US Focus on Africa

by Ikenna Emehelu and Rahwa Gebretnsaie, in New York

The US government took steps in February to ensure that the Power Africa initiative will last beyond when the Obama administration leaves office.

Congress passed, and the president signed, an Electrify Africa Act that directs US government agencies to prioritize loans, grants and technical support for power generation and transmission projects in sub-Saharan African countries.

The statute authorizes the administration to establish an inter-agency working group to oversee these efforts. The Electrify Africa Act has a goal of adding at least 20,000 megawatts of power and providing first-time access to power and power services for at least 50 million people in sub-Saharan Africa by 2020.

It builds on the Power Africa initiative by enlisting more government agencies in the effort. The Power Africa Initiative was launched in 2013 with a goal of doubling access to electricity across sub-Saharan Africa. A major criticism of the Power Africa initiative has been that, as an executive branch initiative without legislative backing, it is not binding on future administrations. The Electrify Africa Act addresses this criticism.

It does not allocate any new funds. The focus is on diverting existing authority for loans, guarantees and grants to leverage private sector capital for African projects. The president is required to deliver a strategy report to Congress by August 2016 outlining the specific steps the government plans to take to implement the new law.

Four Takeaways

Here are four takeaways for stakeholders.

Coal-fired power plants may find new support. The Senate majority leader, Mitch McConnell (R-Kentucky), is from a major coal state. It takes deal making to move any legislation through Congress.

The Electrify Africa Act promotes an all-of-the-above energy development strategy for sub-Saharan Africa that includes the use of oil, natural gas, coal, hydroelectric, wind, solar, and geothermal power and other sources of energy.

The explicit reference to coal is notable. In 2013, the same year that Power Africa was launched, President Obama announced that the US will end its support for public financing of new coal plants overseas with extremely limited exceptions. Republicans decried a "war on coal." The US would only support an overseas coal project if it uses the most efficient coal technology available in the world, is located in the poorest countries and no other economically feasible alternative exists or it uses expensive carbon capture and sequestration technologies that have not proven viable in the United States.

Sponsors of coal-fired projects and African governments saw an opening to lobby for more support for coal-fired projects. In an influential op-ed column published in The Hill, Tony Elumelu and Aliko Dangote, co-founders of the African Energy Leaders Group, urged Congress and the administration to identify an appropriate balance between poverty alleviation and environmental protection and to minimize restrictions on carbon emissions for projects financed in the lowest-emitting countries.

However, the current restrictions on federal support for financing of new coal plants in Africa are unlikely to change in the near term. None of the nearly 240 projects currently tracked by Power Africa uses coal as a fuel.

Renewable energy projects in sub-Saharan Africa are arguably the biggest winners under the new law.

The Electrify Africa Act requires the US government to promote the spread of distributed renewable energy in sub-Saharan Africa, including off-grid lighting and power. The priority given to distributed generation is an endorsement of existing efforts. A sub-initiative of Power Africa, called "beyond the grid," is already focused in this direction.

There are four takeaways from the new Electrify Africa Act for developers working in Africa.

The Power Africa team released a roadmap earlier this year. The roadmap will probably form the basis of the administration's first strategy report to Congress. According to the roadmap, more than three quarters of all projects tracked by Power Africa involve renewable energy. The administration is particularly keen to promote such projects because of the potential to help minimize global warming. We expect US agencies to prioritize funding and guarantees for the renewable energy projects that are currently being tracked by Power Africa.

Another takeaway is the recognition in the Electrify Africa Act that reaching the goals will require international engagement. The new law directs the administration to use the US influence to work toward broader collaboration among international bodies.

US agencies are generally restricted from supporting projects that are not owned by US persons or do not use equipment manufactured in the United States. These eligibility requirements have limited the impact of the Power Africa initiative as non-US sponsors who select non-US equipment are / *continued page 32*

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The bill also increases the state renewable portfolio standard to 50% by 2040. The current target is 25% by 2025. Only four states have more aggressive targets. California and New York require that at least 50% of electricity come from renewable energy sources by 2030, Vermont requires 75% by 2032 and Hawaii requires 100% by 2045.

There are two safety valves under which the state might step back from the new target. First, utilities are not required to add more renewables if the incremental cost to ratepayers will be more than 4% higher than the cost of drawing from non-renewable sources. Second, the Oregon Public Utility Commission can suspend further progress if the new target causes issues with grid reliability.

The coal effort may lead to litigation. Colorado and Minnesota have already had to face off in court with coal interests and utilities in neighboring states over new laws that discourage use of coal.

A public-interest law institute backed by coal interests argued that the renewable portfolio standard in Colorado has the effect of regulating conduct in other states in violation of the part of the US constitution that forbids states from enacting laws that interfere with interstate commerce.

A US appeals court disagreed in 2015. The law institute is waiting for the outcome of a Minnesota case before deciding whether to appeal.

Minnesota enacted a law in 2007 that bars construction of new power plants of 50 megawatts or more in the state that contribute to carbon dioxide emissions unless an offset project is undertaken at the same time to reduce emissions by the same amount. The statute also bars electricity from being imported into Minnesota from such power plants in other states.

North Dakota and various electric cooperatives sued to block enforcement. A federal district court held in April 2014 that the Minnesota law violates the US constitution because it requires coops in other states / *continued page 33*

Africa

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unable to benefit from Power Africa. The Electrify Africa Act requires the administration to use US influence to advocate for international bodies to increase their own contributions to promote investment and broad electricity access in sub-Saharan Africa.

The final takeaway is that the administration is now under orders from Congress to report on what it is doing to promote reforms of the electricity sector in each country receiving assistance. In particular, the administration is supposed to report on its efforts to lower or eliminate import tariffs or other taxes for power production and distribution, to make it easier for independent power producers to connect to the grid, to ensure that power producers get paid for their power, and to allow unbundling of the various services or products that go into delivery of electricity. ◎

Financing Renewable Energy Projects With the US Military

Projects with the US military present special challenges. Financiers focus on the revenue stream. A developer may have a long-term power contract to supply electricity at an agreed price per kilowatt hour. The military also signs energy savings performance contracts (ESPCs) and utility energy services contracts (UESCs) where energy efficiency improvements are installed on a military base and the base is charged a percentage of the energy savings. Several veterans of financing projects with the military and other government agencies talked about the challenges at an Infocast conference on defense renewables in Washington in March. (For prior coverage of this subject, see "The US Army Goes In Search of Electricity" in the February 2013 NewsWire *starting on page 34 and "Power Contracts with the US Military" in the June 2013* NewsWire *starting on page 34.)*

The panelists are Peter Flynn, a partner at Bostonia partners, Robert Johnson, senior vice president for public sector origination with Hannon Armstrong Sustainable Infrastructure, Dan Rosen, director of structured finance for Siemens Government Technologies, and Bharath Srinivasan, senior vice president for operations at Distributed Sun. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: The defense renewables market kicked off with a plan by the US Army in 2012 for $7 billion in power purchase agreements. More than 600 people showed up for an initial meeting in late August 2012 to learn more about the opportunity. Then things seemed to slow down. Contracts are being awarded much more slowly than anyone expected. Bharath Srinivasan, how much opportunity do you see in this market today?

MR. SRINIVASAN: The primary mission of the three divisions — the Army, Navy and Air Force — is to be prepared to fight a war, and energy procurement is secondary to that. We still see a lot of opportunity, but over an extended time period.

MR. MARTIN: Dan Rosen, has this been the opportunity that Siemens expected?

MR. ROSEN: From the Siemens perspective, there is still tremendous opportunity, and there have been tremendous obstacles. It has been a slow and frustrating process. We won some of the early projects. It has been hard since then to win projects that work. It is a very competitive marketplace. We are in this for the long haul.

MR. MARTIN: So you have to be patient. Bob Johnson, big opportunity?

MR. JOHNSON: I agree with the other panelists about the speed with which the opportunity is being realized. It is taking different forms than we expected. We thought it would be more of a finance opportunity. It may not be. We have a huge commercial portfolio under contract currently — almost $3.2 billion, mostly in wind and solar — but we have not seen that kind of volume to date in the federal sector.

MR. MARTIN: If it has not turned out to be a financing opportunity, then what is it?

MR. JOHNSON: It is slow starting.

MR. MARTIN: So no opportunity?

MR. JOHNSON: No. Some opportunity, but the opportunities have been few and far between. The announcements about potential new projects are months apart followed by a long gestation period to get each project off the ground. There is a huge time lag between when a contract is awarded to a developer or contractor to when the project is ready to put shovels in the ground.

MR. MARTIN: How many contracts have been awarded under the program since 2012?

MR. FLYNN: Since I don't know the exact number, I will say not enough.

MR. MARTIN: Does anyone have a number? Dan Rosen?

MR. ROSEN: I would say too few as well, but to follow up on a point that Bob Johnson made, we are here representing capital. Capital is fungible. We like to invest in renewable energy projects. We have other opportunities besides the federal sector to deploy our capital. Anyone interested in supplying capital to fund federal projects must be really patient and must have a very low cost of funding to be able to survive in this environment.

MR. FLYNN: I will give you a number relative to the total market size. Focusing on the ESPC and UESC market, depending on the year, there may be anywhere from $600 million to $1 billion in projects awarded.

MR. MARTIN: That is a very large number.

MR. FLYNN: There is a significant pipeline of projects, but as has already been noted, there is a time lag of 18 to 24 months after a project is awarded before it is ready for financing. Most renewables developers who follow this market appear to see the federal renewables market as a $3 to $4 billion opportunity overall.

MR. MARTIN: Over what time period?

MR. FLYNN: Over the next few years as the market currently exists. More opportunities may develop later.

MR. MARTIN: Somebody please put this into context. Lots of people attended the Infocast defense renewables conference in 2013. By 2014, interest seemed to be waning. Attendance was not so great. I wasn't here in 2015. Are the attendance and mood like 2014 with developers feeling disappointed or are things picking up again?

MR. FLYNN: It is important to view the market holistically. I think that is why Dan Rosen and Siemens are still here when some others are not. Siemens, Honeywell and others have a broad view of the market. They are big companies with staying power. Smaller companies invested some resources initially, but they have moved on because the opportunities and pipeline are not what they expected.

MR. SRINIVASAN: The program should continue to grow. Developers have had to spend a lot of time to date educating base-level contracting officers dealing with smaller projects. Once the larger projects start being awarded and once we get greater standardization of terms because the contracts are being reviewed at higher levels, then the pace should start to pick up.

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effectively to seek approval from Minnesota before undertaking a transaction in another state. The case is now before a US appeals court. (For more details about the Colorado and Minnesota cases, see the September 2015 *NewsWire* starting on page 27.)

OKLAHOMA will go at least another year without scaling back production tax credits for wind or adding new incentives to use natural gas.

The state faces a $1.3 billion budget shortfall in 2015.

The state legislature has been considering three bills to scale back an existing tax credit of 0.5¢ a kilowatt hour for generating electricity from wind and a separate bill to establish a 75% natural gas energy standard by 2020. The bills missed a March 10 procedural deadline to move to a third reading in the chamber of origin. They had cleared the committee stage. The current legislative session is expected to end around May 27. The bills are expected to be reproposed next year.

One of the wind bills would have cut off tax credits for new wind facilities placed in service after 2016. Another would have reduced the tax credit by 25% starting in July 2016. The third would deny any tax credits on wind electricity generated after 2017 unless the state legislature reauthorizes the tax credit after hearing from an evaluation body it set up to look at state tax incentives.

Wind accounts currently for 18% of electricity in Oklahoma. Other renewables account for another 2%. The state reduced its severance tax on oil and gas production last year to 2% from 7%. The reduced rate only applies to the first 36 months of production from new wells spudded in after the rate decrease.

A REFINED COAL TRANSACTION got raked over on audit.

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Termination for Convenience

MR. MARTIN: I want to dive into some details that have made it challenging to finance projects with the US military. Projects on US military bases are getting financed, but the facts that the military retains the right to terminate the power contract for convenience and, depending on the contract officer, it may or may not agree in advance to a schedule of termination payments have been a significant impediment to raising financing. Is this still an issue and, if so, how common?

Projects with the US military present special financing challenges.

MR. ROSEN: It is an issue, but a solvable one. People may differ about whether it is a drop-dead issue or something that can be overcome. From a Siemens Capital perspective, there has to be a termination payment schedule and we have to feel comfortable that it is enforceable.

MR. MARTIN: So for you, it is a go, no-go issue. Does anyone have a different perspective?

MR. JOHNSON: The termination payment must cover a number of items. The financier wants to be repaid the principal amount of its investment plus accrued, but unpaid, interest on that investment with no questions asked. There may also be costs, like swap breakage charges, that also need to be covered.

The deal structure may also affect what should happen upon termination. It is easier to deal with termination where the project is on the military base and all the output goes to the base, but what about where there is also a power contract to supply part of the output to someone off the base? How does termination for convenience work in that case?

In many projects, there is also the complication of a tax equity investor. A termination for convenience may cause recapture of tax benefits for which the tax equity investor will require compensation.

Finally, what happens if the military says it has to take over the project due to national security concerns: what happens then? I don't know that we have crossed that bridge yet.

MR. MARTIN: That is a good list. Is it true that it is up to each individual contract officer to decide whether there will be a termination payment schedule?

MR. JOHNSON: The government is a decentralized organization, from a contracting standpoint as well as from a legal standpoint. You see it at this conference with many different people from the Pentagon and the service branches expressing different opinions. Each contracting officer can make his or her own decisions about the best way to address local issues on the base. Each can take a different approach.

MR. MARTIN: Are some of the service branches better at this than others? Peter Flynn? [Laughter]

MR. FLYNN: All right. I'll go. In cases where the developer has an enhanced use lease or other form of lease allowing use of real estate for offsite power sales, what has seemed to work is to secure an exception from the secretary of the Army, Navy or Air Force to allow termination only where there has been a default by the developer. That seems to work for lenders.

MR. MARTIN: Is that true? What if there is a national security issue?

MR. FLYNN: That is a more difficult issue. What we have seen when the assets are on the military base and the power goes offsite, the only termination would be through default of the contractor. Otherwise, the lease would stay in place. If you introduce termination or suspension for national security reasons, then you end up with a smaller number of potential investors who can get comfortable with the risk. It is really difficult to quantify the national security risk. What kind of discretion exists around that? Can it be whittled down to specific events?

In cases where the government is buying the electricity under a long-term power contract from an asset behind the fence, you really look for a pre-agreed schedule of termination payments.

The termination-for-convenience issue started with the Navy requiring that termination payments are fully negotiable, which is a non-starter for tax equity investors and lenders. Now we are in a position where a par-value termination payment is permitted, but all other costs are negotiable, which is very difficult for many investors and requires at least a significant pricing premium.

MR. MARTIN: So did you answer my question: is one service branch better than the others? [Laughter]

MR. FLYNN: I think each service has its strengths. For example, the Navy at least has said, "We want to engage and solve this."

Non-Appropriation Risk

MR. MARTIN: The next risk is non-appropriation or the possibility that Congress might not provide funds to make payments. Is this still a fear for anyone? Bob Johnson, you are nodding your head no.

MR. JOHNSON: I don't think it is.

MR. MARTIN: Why not?

MR. JOHNSON: That is a risk that we underwrite as financiers of federal, state and municipal projects every day. We are looking at an offtaker that is a AA+ or AAA credit.

MR. MARTIN: You have more confidence in Congress to appropriate money than the American people do.

MR. JOHNSON: Non-appropriation for us is more of a concern in some of the deals we do with municipalities.

MR. ROSEN: It is a different analysis on the federal side. Most financiers working in the federal sector understand that there may sometimes be payment delays — for example, as we have seen during the recent budget sequestrations — but it is not a matter of never receiving payment.

MR. FLYNN: Non-appropriation risk is different for many federal transactions in part because the military has been given multi-year contract authority for certain types of contracts like ESPC and UESC agreements. Congress has said, "We're giving you authority to enter into these long-term agreements," and Congress does not have to come back each year and appropriate funds for the contract payments.

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The IRS released a heavily redacted internal memo in March indicating that it is moving to disallow production tax credits claimed in a refined coal transaction on grounds that the tax equity investor is not a real partner in a partnership that owns the refined coal facility.

The memo is a "field service advice" by an associate area counsel in the IRS field to an IRS agent who asked how to handle a deal that the agent is reviewing on audit. The memo is Field Service Advice 20161101f.

The audit is under the CAP program, meaning the tax equity investor is a large taxpayer whose transactions are audited in real time by the IRS.

The transaction structure is fairly typical for refined coal deals.

The US government allows a tax credit of $6.71 a ton for producing refined coal. Refined coal is coal that has been treated to make it less polluting. It must produce at least 20% lower nitrogen oxide emissions and at least 40% lower mercury or sulfur dioxide emissions when burned compared to the raw coal used to make it. The tax credit is claimed by the producer of the refined coal and can be claimed for 10 years after the refined coal facility is first put in service. All such facilities had to be in service by the end of 2011 to qualify for tax credits. The tax credit amount is adjusted each year for inflation. The figure $6.71 a ton is the 2015 tax credit.

Three structures are being used to transfer tax credits to tax equity investors.

The deal under audit used a partnership structure.

The tax equity investor under audit paid a sponsor for an interest in a partnership that owns the refined coal facility. There is more than one tax equity investor in the deal.

Each investor made an initial payment to the sponsor that is amortized over an initial period. It then makes fixed and variable quarterly payments. There is a cap on the total payments that are required each quarter. The variable payments are an amount

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US Military

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MR. ROSEN: Failure to appropriate on the municipal side would be a real problem.

MR. SRINIVASAN: Look at the electricity prices in these contracts. The military is being offered electricity at below the rate it pays the local utility. The base needs the electricity. It is not likely to stop payments for power from the independent generator in order to pay more to the local utility. This helps to minimize the risk.

Seizing Collateral

MR. MARTIN: These projects require outside financing. There may be a lender. There may be a tax equity investor. What happens if there is a default? The project is on a military base. Can the financiers come in and take over or remove the asset. If not, is this an issue?

The military can terminate contracts for convenience. It may or may not agree to a schedule of termination payments.

MR. FLYNN: Lenders want step-in rights. They want the ability to control the asset and fix the problem. They also want to receive copies of any default notices sent by the military to the developer and vice versa. In reality, it is unlikely that a lender will pull equipment at an installation like Fort Bragg. That is difficult to do. But lenders need that right in the contract in the event of a default. It will be an important part of the financing package.

MR. MARTIN: Bob Johnson, as a lender, you probably do not want to take back the asset in any event. You want to be able to leave it in place and sell it to someone else.

MR. JOHNSON: All we want is to get paid at the end of the day. If it is the government that is in default by not making contract payments, then that is the non-appropriation risk that we evaluated and agreed to take. If the developer is in default, either for failure under the EPC contract or an O&M contract, then we want step-in rights and the ability to fix the problem without losing the power contract with the military. At that point, we are acting on behalf of the government to make sure that the solar array does what it is supposed to do with another contractor that we have agreed with the government to bring in to replace the original developer. We are working collaboratively with the government at that point. Our interests are aligned with the government and not in conflict.

MR. MARTIN: You just want the government to recognize that you have an interest in the asset and want the ability to step in after a default to fix things before the project is lost.

MR. ROSEN: Speaking as a representative of Siemens, that is why it is important to deal with contractors who can finish the job.

Power Prices

MR. MARTIN: The next topic is power prices. The military wants to buy electricity from renewables at lower cost than it pays the local utility, and yet these are technologies that are more expensive to produce electricity than from gas or coal that the local utility may be using. In addition, the Army, at least early on, wanted to keep the renewable energy credits that are supposed to close the gap for the developer. How is this requirement that renewable energy be supplied at lower than the local retail rate working out in practice?

MR. SRINIVASAN: The reality is that it is difficult to bifurcate the RECs in most markets. The offtaker often takes the RECs as part of the price it pays for the electricity.

MR. ROSEN: Do you have any customers who are willing to pay more than the local utility rate? [Laughter] We would love to sell to them. We work with states, municipalities, universities, schools, hospitals, the federal government; we are all over that space. We have not found a customer yet who said, "We are going to put a value on the fact that this is clean energy, and we will pay you a premium for the electricity." Every customer says, "We love to have solar, but we really want to save money at the same time."

MR. MARTIN: That is an excellent point. Peter Flynn?

MR. FLYNN: I agree with that. The difference is that the military is interested in keeping the RECs as a way of meeting renewable energy goals while, in the private sector, the RECs are sometimes left with the developer or folded into what is sold to the offtaker under the power contract.

MR. MARTIN: What about the risk of future political pressure to amend the contract terms? These are long-term contracts, 25 years in some cases and perhaps as long as 30 years in other cases. The electricity price is agreed in year 1. There may be a fixed inflation adjustment written into the contract. Are you worried that, over time, the electricity price being paid under the contract will end up higher than the local retail rate and that there will be pressure to change the contract?

MR. ROSEN: We are not too concerned in the federal space. We do this ESPC work all the time. There are fixed escalations. Government agencies live with these contracts. Really, their goal is to get a project that gets them either the energy savings or the renewable resource that they wanted and, while it may be uncomfortable for some contract officers to have to acknowledge to a base commander that an occasional contract has become way out of the money, there are plenty of contracts that are in the money.

MR. FLYNN: No developer asks for revisions in pricing when the shoe is on the other foot and retail prices have risen.

Other Risks

MR. MARTIN: Are there other risks with military contracts that are not present in a utility or commercial deal? What about the risk that the military base will be closed during the contract term?

MR. JOHNSON: Base closure is a risk that we take into account, and it can be a big one, depending on the location of the base. If solar panels are being put on privatized housing on a base, then the risk is a little different because the project is tethered to the military through a commercial contract. You have to assess whether that housing has intrinsic value in the market apart from its use to house military families.

There is also general political risk. The political risk is not around a price for electricity in the PPA. It is the risk that the US government may have less interest, after the upcoming change in administrations, in promoting use of / *continued page 38*

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per ton of refined coal produced, minus the fixed payments and ongoing capital contributions to cover operating costs. There is an "annual adjustment amount" to keep the total payments linked to actual output.

After a "tax event," like an IRS challenge to the tax credits, the investors can notify the sponsor to suspend production and then, with a time lag during which the sponsor is supposed to negotiate with the utility that is taking the refined coal, the investors can direct that the contracts with the utility be terminated.

The partnership buys raw coal from the utility and sells back refined coal at the same price.

The partnership pays for the raw coal with some cash and the balance with a promissory note. The amount owed for raw coal is probably netted against the amount the utility owes for the refined coal.

The sponsor has an option to buy the investor interests in the partnership for fair market value after the refined coal credits expire.

The IRS is not challenging whether the facility is producing refined coal.

Rather, the memo suggests the agency take the position that the tax equity investor under audit is not a real partner in the partnership that owns the refined coal facility. Only a partner can share in tax credits.

The memo points to the following to support the view that the investor is not a real partner.

The investor payments have been set up so that the investor takes little risk that it will have to pay more than is justified by actual tax credits, and the rights to suspend and terminate the utility contracts are additional protection. The "fixed" quarterly payments by the investor are not really fixed because the only recourse the sponsor has to collect them is to take back the investor's interest in the partnership. The memo acknowledges that the investor is exposed to potential loss of its initial payment, but information on how long it takes to recover the initial payment is redacted. / *continued page 39*

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renewable energy on military bases. We won't know whether the basic program will undergo major changes until next year. That is a risk that will affect the velocity and number of future projects.

MR. SRINIVASAN: Another risk is that anything with the government takes a long time. Renewable energy procurement is just a small part of what the US military does. We see a lot of risk in the time that it takes to go from point A, which is notice of award, to point B, which is when the project is ready to begin construction. That is the largest risk in these projects. Once the project is in operation, we don't see much risk, including the inflation risk that was discussed earlier.

MR. ROSEN: I agree with that. There is also an opportunity cost to chasing military projects. It is spending so much time and not knowing whether you will be able to get the contract. That is the biggest risk for us.

MR. JOHNSON: In the fall 2008 to early 2009, interest rates went crazy and credit dried up. Another risk, because of the long time it takes to move these projects through the queue, is that there will be a similar financial event that will put a project out of the money. The risk is of a global financial event that pushes up interest rates and pushes the price at which you can supply electricity above what you had to promise to win the contract.

There is a need to shorten the timelines. We have seen credit risk increase since 2014. Corporate bond spreads are widening. The longer it takes to move a military project from contract bid to financing, the greater the risk of a major credit event happening to put the project out of the money from the developer side.

MR. MARTIN: Let me ask a question that calls for a one-word answer. Are these projects riskier, less risky, or just different from utility and commercial projects?

MR. SRINIVASAN: They are different.

MR. ROSEN: I would say the same: different risks. Maybe they are a little less risky once you get immersed in them, but different.

MR. JOHNSON: Different set of risks.

MR. FLYNN: Different.

Cost of Capital

MR. MARTIN: Let's move to the cost of capital. You have a federal government credit behind the revenue stream. Does that mean that the cost of tax equity and debt is lower than for a utility- or commercial-scale project?

MR. ROSEN: Debt, yes, tax equity, no.

MR. MARTIN: Why the difference?

MR. ROSEN: The federal government is the gold standard from a lender's perspective. Tax equity costs what tax equity costs.

MR. MARTIN: Debt is priced based on the creditworthiness of the revenue stream. Tax equity does not move with interest rates because tax equity investors are selling tax capacity. It is a scarce resource. What is the premium to treasuries for debt in this type of transaction?

MR. FLYNN: My price is several points below Bob Johnson's. [Laughter]

MR. MARTIN: Looks like we are about to have an auction. Do we have an opening bid? [Laughter]

MR. FLYNN: At the end of last year, we were executing well-structured projects at under 100 basis points.

MR. MARTIN: Under 100 basis points above average-life treasuries? You are talking about executing in the securitization market, right?

MR. FLYNN: In a form of it. In the private placement market. Credit spreads have widened since then. I think you are looking

The market has gotten comfortable with non-appropriation risk.

at 120 to 140'ish in this environment, depending on where the project is.

MR. MARTIN: What's the average life treasury right now? What's the base?

MR. ROSEN: It depends on the term. If you have a 20-year term, the debt life is around 12 or 13 years, depending on interest rates. It is a calculation.

MR. FLYNN: Today the 10-year treasury rate is 1.97%.

MR. MARTIN: So if you add 125 basis points, you are up to 3.22% as an interest rate.

MR. FLYNN: If you are going into a PPA with more risk, then there might be a four as the first number.

MR. MARTIN: Which is not bad. Look at the rooftop solar securitizations that SolarCity and Sunrun have done. Until the first quarter this year, they had been in the 4% to 5% range. The securitizations in the first quarter this year have been in the high 5% to 6% range as an all-in interest rate.

MR. FLYNN: That is a commercial deal. Those are private companies and not the federal government. It is a different equation than for a UESC at a military base, which has the lowest possible spread because it is viewed as very close to a federal government credit.

MR. MARTIN: This proves Dan Rosen's point that the fact that you have a federal government credit behind the payment stream leads to a lower interest rate than in the commercial market. On the difference between bank spreads and securitization, there may be a 125-basis point spread above treasuries for a securitization. Banks offer a floating interest rate that is at a spread above LIBOR. Do you know what the spread is currently when borrowing from a bank against a federal government payment stream?

MR. FLYNN: It depends on the kind of project. With a UESC, there is political risk but no variability in the payment stream. With privatized military housing, there is more risk tied to the payment stream.

MR. MARTIN: Correct me if I am wrong. We are talking about three types of projects. A UESC is a contract with the local utility to install energy efficiency improvements. An ESPC is a contract for energy efficiency improvements where the price paid is a percentage of the energy savings each period. A PPA is a contract by a generator to sell electricity.

MR. ROSEN: A UESC is the least risky because there is no variability in the payment stream. ESPCs and PPAs go up the risk scale. Even higher on the risk spectrum is solar panels mounted on privatized military housing. / continued page 40

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The promotional information given to investors was focused on tax benefits. It "indicates the parties were interested in the generation and allocation of tax benefits, not in undertaking a joint endeavor to operate a profitable refined coal facility. The main focus . . . is the tax credits." Almost all the risks highlighted in the risks section of the promotional material were things that affect the tax credits.

The quarterly operations reports to the partners are focused on information relating to tax credits.

The investors are indemnified against loss of tax credits if the sponsor misrepresented anything or breaches its duties to the investors.

The investors are not involved in decision making about the refined coal facility. The utility that takes the refined coal is effectively making all the decisions about operation.

The investors have no real downside risk, apart from the initial payment that is recovered quickly, and no upside potential apart from tax credits. The refined coal operations lose money because the partnership is paying the utility to take the refined coal through payments for use of the site and for use of equipment on site to move the coal.

In most refined coal deals, the utility can cancel the contract to buy refined coal after only a short notice period. The memo does not mention this risk to the investor.

SOLAR SUBSIDIES paid by a state to homeowners to encourage them to install rooftop solar systems do not have to be reported by the homeowners as income, the IRS said.

Section 136 of the US tax code spares utility customers from having to report subsidies received directly or indirectly from utilities to help pay for energy conservation measures at a "dwelling unit."

The IRS analyzed a state program in a private letter ruling made public in February. The state set up an organization to help finance clean energy facilities in the / continued page 41

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MR. MARTIN: Let's talk then about that spectrum. What would the required debt-service-coverage ratios be across that spectrum?

MR. ROSEN: I am sure that Peter's will be 1.5x. [Laugher]

MR. MARTIN: Peter Flynn, do you want to defend yourself?

MR. FLYNN: It is 1.35x for a solar PPA. It is not much different than the commercial credit space.

Debt is cheaper for military projects; tax equity costs the same as for commercial projects.

MR. MARTIN: I see everybody else nodding in agreement.

MR. ROSEN: It is 1.35x for a P50 revenue projection. In a P99 case, the ratio is 1.0.

MR. MARTIN: Most finance in this market is either debt or tax equity or some combination of the two. What both have in common is that financers want to see a true equity layer of at least 10% or 15%. Are the returns for developers in these projects high enough to attract that much true equity?

MR. SRINIVASAN: Yes in most cases where a project ends up being built. We have done a number of contracts with the Army.

MR. MARTIN: Peter Flynn, how much true equity do you want to see?

MR. FLYNN: It depends on the contract structure, but, in general, it is the same as for a commercial project. We like to see at least 10%.

MR. JOHNSON: We want as much true equity as possible. We want to see the sponsor have a strong incentive to make the project work.

MR. MARTIN: Is it a common mistake for smaller developers not to realize that they will have to have significant equity to raise other financing?

MR. JOHNSON: It can be sometimes. We have had people come through with little understanding of what the process is from a financing standpoint. They think they just put up panels and make it work, and it is a rude awakening sometimes when the reality sets in.

MR. SRINIVASAN: It is how much equity versus how long the sponsor will have the equity in the deal. Many deals have tax equity. We have invested in projects where the equity may be a smaller portion of the capital structure, but the sponsor waits until the tax equity has reached its return before it starts to get back its invested capital.

MR. MARTIN: Bharath Srinivasan, you said developer returns are high enough to attract the equity required. The obvious follow-up question is what are the developer's returns?

MR. SRINIVASAN: The sponsor return is somewhere in the low double digits. That is for commercial projects. Returns on projects with the federal government may be a little lower, but I don't think we are seeing a significant gap between the two.

MR. MARTIN: Dan Rosen, is that what Siemens earns?

MR. ROSEN: We have hurdle rates. I don't know what sponsors are earning on the equity investments in these projects, but my guess is it is not a lot.

MR. MARTIN: Peter Flynn, what has been the default rate on securitizations involving government paper?

MR. FLYNN: To use that term securitization somewhat broadly, it has been zero in the ESPC and UESC markets. There have been no defaults in fact.

MR. MARTIN: Over what time period?

MR. FLYNN: Since initiation of the program. Actually, I think Enron had to walk away from one of its projects, but there was no default because the contract allowed the lender to find a replacement contractor without default. ◎

World Bank Guarantees for Private Projects

by Anthony Molle with the World Bank and Kenneth Hansen with Chadbourne, in Washington

The World Bank has rolled out an enhanced guarantee program, building on 25 years of experience in issuing "partial risk" and "partial credit" guarantees.

The enhanced guarantee program was recently showcased in the project financing of the 450-megawatt gas-fired Azura power project in Nigeria. This project reached financial close in December 2015 and was supported by two World Bank partial risk guarantees.

The bank's pipeline of proposed guarantees is growing to unprecedented levels, with dozens of potential projects currently under consideration. That demand suggests that these products address real needs in the relevant markets.

This article summarizes the key features of the new forms of guarantees on offer and explores the potential impact on investment in emerging markets.

History

The World Bank was originally expected to make its primary activity guaranteeing repayment of commercial bank loans to governments in less developed countries and taking participations in such loans.

Contrary to expectations, the bank's dominant activity since it was established in 1945 has been making direct loans to sovereigns or, subject to a sovereign guarantee, to sub-sovereigns. For a variety of reasons, guarantees have been used only sporadically. Bank guarantees traditionally have helped countries mobilize private financing by protecting private lenders against the risk of debt service default by the borrower as a result of a host government's failure to fulfill its contractual obligations related to the project.

All World Bank guarantees require a sovereign indemnity of the bank in order to satisfy the bank's charter obligation to take only sovereign credit risks.

The bank took a step toward issuing guarantees in 1983 by opening a B-loan program in which commercial lenders could co-finance projects with the bank by / *continued page 42*

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state. The organization pays solar installers part of the cost of solar rooftop systems installed on homes. The subsidies are funded through a surcharge collected by utilities on electricity bills. The utilities remit the surcharges directly to the state organization, and they are kept in a special account.

There are three complications when trying to fit the program under section 136. One is the subsidies are paid by the state rather than the local utility. Another is they are paid to solar installers rather than homeowners. The installers then reduce the amount they charge homeowners. Another complication is the state organization requires assignment to it of the renewable energy credits to which the homeowner is entitled for generating solar electricity in exchange for the subsidy.

The IRS ruled in 2010 that a utility customer who transferred his rights to renewable energy credits to his local utility in exchange for an up-front payment to help defray the cost of a rooftop solar system sold the renewable energy credits to the utility and had to pay tax on the up-front payment. The IRS appeared to reverse course in 2013 in private rulings issued to two utilities about a similar program. It said in 2013 that there is no forward sale of RECs because the utility customers do not promise any particular amount of RECs to the utility in exchange for the up-front payment. (For earlier coverage, see the December 2013 *NewsWire* starting on page 9.)

The latest ruling suggests the IRS may still be struggling with the issue. The IRS said the subsidies do not have to reported by homeowners as income because they are paid indirectly by utilities. The utilities are not buying RECs because the RECs remain with the state organization. The IRS said the state organization does not have to report the payments to the IRS. Section 6041 of the US tax code requires anyone engaged in a trade or business to report all payments of $600 or more during the year. No reporting is required in this case because the payments are not income to the recipients. / *continued page 43*

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purchasing participations in certain World Bank loans. The bank suspended that program in 1988 because of concerns raised about certain risks in that structure, but that led in 1988 to the establishment of the "Expanded Co-financing Operations Program." The revised program focused on using partial — versus all-risk — guarantees to mobilize private finance for public or joint public-private projects.

Shortly thereafter, in 1991, the bank broadened the program also to permit guarantees to support commercial financings for private sector projects. The trend at the time was toward greater private sector involvement in public infrastructure projects, and financings were being done on a limited-recourse project finance basis. The Hub power project in Pakistan was the first application of the guarantee to such a private sector project. The guarantees opened the door to a World Bank role in projects that would otherwise have had no access to traditional World Bank lending.

In 1994, the World Bank board approved the use of partial risk guarantees and partial credit guarantees.

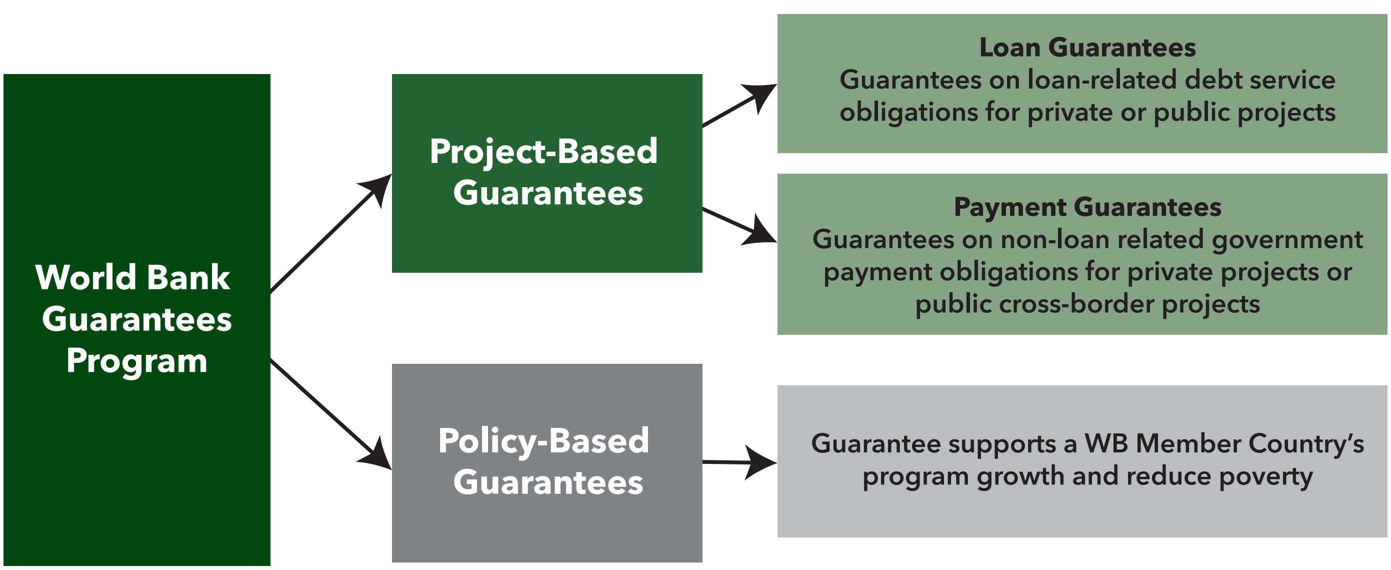
A partial risk guarantee protects private lenders against debt service defaults on loans, normally for a private sector project, when the defaults are caused by a government's failure to meet specific obligations under project contracts to which it is a party. Partial risk guarantees were available to both "IBRD-eligible countries," which are the higher-income borrowing members of the World Bank, as well as to "IDA countries," which are the lower-income members.

A partial credit guarantee protects private lenders against debt service defaults on a specified portion of a loan, normally for a public sector project, irrespective of the cause of the default. Partial credit guarantees were only available to IBRD-eligible countries.

While this World Bank guarantee program was an exciting development in theory, actual deployment of the guarantees was relatively limited for two reasons.

First, for the first decade of the program, the guarantees were offered only as a source of World Bank Group (IBRD/IDA, IFC and MIGA) support of last resort. Project developers were encouraged to seek debt from the International Finance Corporation and investment guarantees against political risk from the Multilateral Investment Guarantee Agency. Only if such support was unavailable, and only upon successful navigation of a host of other bureaucratic and policy barriers within and beyond the World Bank such as getting the host government to sign the required indemnity agreement, might an application for a World Bank guarantee receive serious attention.

In 2005, the World Bank decided to lower the barriers to entry into the partial risk guarantee program, recognizing that the guarantee can add value because the more conventional investment support programs through the IFC and MIGA might not



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A World Bank enhanced guarantee helped a power project in Nigeria reach financial closing in December.

address the sovereign risks of projects that depend on host government undertakings. The IFC, as a lender to private borrowers, can be deterred by the very risks of governmental breach that the partial risk guarantee program addresses. While MIGA insures against government misbehavior, it does so without a host government indemnity and without the heavy club of potentially cross-defaulting all of the host country's outstanding World Bank loans. These two branches of the World Bank Group offer private investment support that can be complementary to the partial risk guarantee. The previous treatment of such support as substitutes rather than complements limited the availability and effectiveness of the partial risk guarantee program.

A second factor constraining host government demand for partial risk guarantees has been their accounting treatment at the World Bank. Originally, the face amount of a partial risk guarantee was fully counted against a country's borrowing limit. In that case, if a host government were to accept a US$100 million partial risk guarantee, then it would have received no cash, only enhanced credibility permitting a privately-sponsored project to go forward. However, the ability of the host government to borrow from the Bank for public purposes, like schools and roads, was reduced by the full US$100 million. This rendered the program substantially useless for the poorest countries, which were inclined to allocate their borrowing capacity to actual borrowing rather than supporting the creditworthiness of private projects.

The World Bank in 2005 took several steps to enhance the availability of the partial risk guarantee program.

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The IRS issued the ruling to the state organization. It is Private Letter Ruling 201607004. The redacted version made public does not reveal the state.

A SOLAR PROJECT will be considered in service for tax purposes even though the utility with which the project is interconnected has not finished the intertie to connect the project to the grid as long as the project has a temporary means to get electricity to the grid, the IRS said.

The IRS made the statement in a private letter ruling released in March. The ruling is Private Letter Ruling 201611011.

The ruling is in keeping with other rulings the IRS has issued to wind and at least one other solar developer.

In the other rulings, the developers were able to deliver at least 20% of their electricity to the grid through a temporary route. The percentage in this case is redacted.

A power project is not in service until it can deliver its electricity to the grid.

Some solar developers were concerned, before Congress extended the 30% investment tax credit for solar facilities last December, that utilities might take longer than expected to complete interties needed for interconnection, thereby preventing projects from making it into service by a December 2016 deadline to qualify for tax credits. When Congress extended the tax credit, it moved the deadline back to December 2019 and converted it into a deadline merely start construction rather than to complete projects. (There still is an outside deadline to complete solar projects by December 2023 to qualify for an elevated tax credit.)

The ruling involves two utility-scale solar photovoltaic projects. The intertie for one of the two projects may not be ready in time.

The developer planned to run electricity from both projects through the same intertie, requiring both projects to operate at reduced capacity until the permanent intertie for the second project is ready.

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First, partial risk guarantees were no longer banned from IFC- or MIGA-supported projects.

Second, the bank around 2008 reduced the credit limit disincentives for host countries to use the partial risk product so that only 25% — versus the previous 100% — of the amount of a guarantee would count against a country's borrowing limit.

Third, project sponsors (or lenders or host governments) were for the first time invited to approach the World Bank directly, without prior approaches to MIGA or the IFC, for an initial expression of the bank's interest in supporting a project.

Finally, the bank announced that, going forward, guarantees could be available to support equity investors as well as lenders. This was a structural innovation rather than a formal change to the program. Equity could benefit from the partial risk guarantee through a letter of credit that is posted to guarantee performance of the host government's obligations. If the government breach of its undertakings causes a loss, then the letter of credit can be drawn. The beneficiary of the letter of credit can be either a lender or equity investor. If the government does not reimburse the letter-of-credit bank within a certain waiting period, then the World Bank will do so, with recourse to the government pursuant to the indemnity agreement. Multiple deals were closed under this structure, including most recently the Azura power project in Nigeria.

Notwithstanding the 2005 enhancements and a record three partial risk guarantees closed that year, the bank reverted to its more usual pace in issuing partial risk guarantees over the following decade of about one partial risk guarantee a year. The bank decided that it could and should do better.

Motivation for Further Reform

More guarantee program reforms were introduced in 2013 in an effort to further enhance the guarantee to address several issues and opportunities.

More private capital is needed for public infrastructure projects. The financing needs of the developing world are large and growing. The gradual withdrawal of quantitative easing in high-income countries is leading to tighter credit conditions for developing economies. Even for developing countries that have made positive strides in market access, keeping the private financing flowing to support development is a challenge.

World Bank guarantees have not been used to their full potential. Limitations in access, policy constraints and gaps that lead to a perceived lack of clarity and added complexity by program participants have been obstacles.

Projects are increasing in size. The bank's increasing capital constraints prevent it from participating in certain high-cost projects and programs that may be transformational and can have a significant impact on poverty reduction and shared prosperity. A more accessible and flexible guarantee policy framework helps to relieve those limitations.

More flexible and accessible guarantees allow the World Bank Group to work together more effectively to tackle client needs and catalyze private sector participation in member country projects.

The bank took a first step toward reforming the guarantee program on June 26, 2012 when it replaced its environmental and social safe- */ continued page 46*

Dozens of other projects are currently under consideration for similar guarantees.

guards policies with a new set of performance standards for financing of projects that are owned, constructed, or operated by the private sector. The previous dual system of the bank safeguards policies on one hand and the IFC/MIGA performance standards on the other had been a significant drag to joint World Bank Group support of public-private partnerships.

What's New?

The reforms have introduced the following key updates to the prior program of partial risk guarantees and partial credit guarantees.

Under the previous policy framework, the World Bank only guaranteed commercial loans. To meet the needs of infrastructure projects where bankability is constrained by the credit risk of project counterparties, such as offtakers or, in the case of termination payments, local utilities and host governments, guarantees can now run in favor of the direct beneficiaries of a sovereign undertaking, such as the project company, rather than just being in favor of lenders.

The World Bank has traditionally offered partial risk guarantees to ensure repayment of draws on commercial bank letters of credit or by converting the host government payment obligations into a World Bank-guaranteed loan. While useful in some cases, this approach may add to the complexity and transaction costs of already complex project financings, adversely affecting client countries. Furthermore, clients are increasingly seeking World Bank guarantee coverage of non-debt-service-related government payment obligations not only in favor of private entities but also foreign public entities, where such payment obligations require credit enhancement if the project is to be bankable.

Under the prior policy framework, such guarantees could be designed in principle, but only through very complex structures that increased transaction costs and could deter their use.

The scope of bank guarantees has now been expanded to cover payment defaults in non-loan-related government payment obligations, where three things are true. The payment guarantees will help facilitate investment and serve clear development objectives under the same policy conditions that apply to bank loans. The guaranteed obligation is a direct payment obligation of a government or a state-owned entity. The guaranteed obligations would be subject to an adequate dispute resolution framework so as to avoid entangling the bank in the substance of a contractual dispute.

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This arrangement would remain in place for an indefinite period. The developer said the arrays at both projects will be rotated on one-week intervals to make sure each array is operating a reasonably consistent number of hours overall.

WARRANTS are addressed by the IRS.

Banks and tax equity investors sometimes ask for warrants in a project developer in exchange for financing one or more of its projects. The warrants entitle the bank or tax equity investor to buy shares in the developer for a period of time at an agreed price.

The IRS addressed the tax consequences of warrants in a private letter ruling that the agency released in March. The ruling is Private Letter Ruling 201610006.

The company that asked for the ruling is a US corporation that buys products from suppliers and resells them. It entered into a contract with a foreign supplier and granted warrants to the two owners of the foreign supplier giving them the right to buy shares in the US corporation at an agreed price that was above the current share price. Exercise of the warrants was contingent on performance of the supply contract by the foreign supplier: the warrants could be cancelled if the foreign supplier failed to perform.

Anyone receiving warrants for providing services must report the value of the warrants as additional compensation. The question is when.

If the warrants have no readily ascertainable value when granted, then they are not reported immediately as income. The value is also not reported until the warrants vest, meaning that the holder is free to transfer them and they are not subject to a substantial risk of forfeiture. If the holder has not already been taxed on them, then he is taxed when he exercises the warrants or sells them to someone else. His income is the difference between the market price of the shares and the discounted price at which he was allowed to purchase them.

The company granting the warrants is usually allowed to / continued page 47

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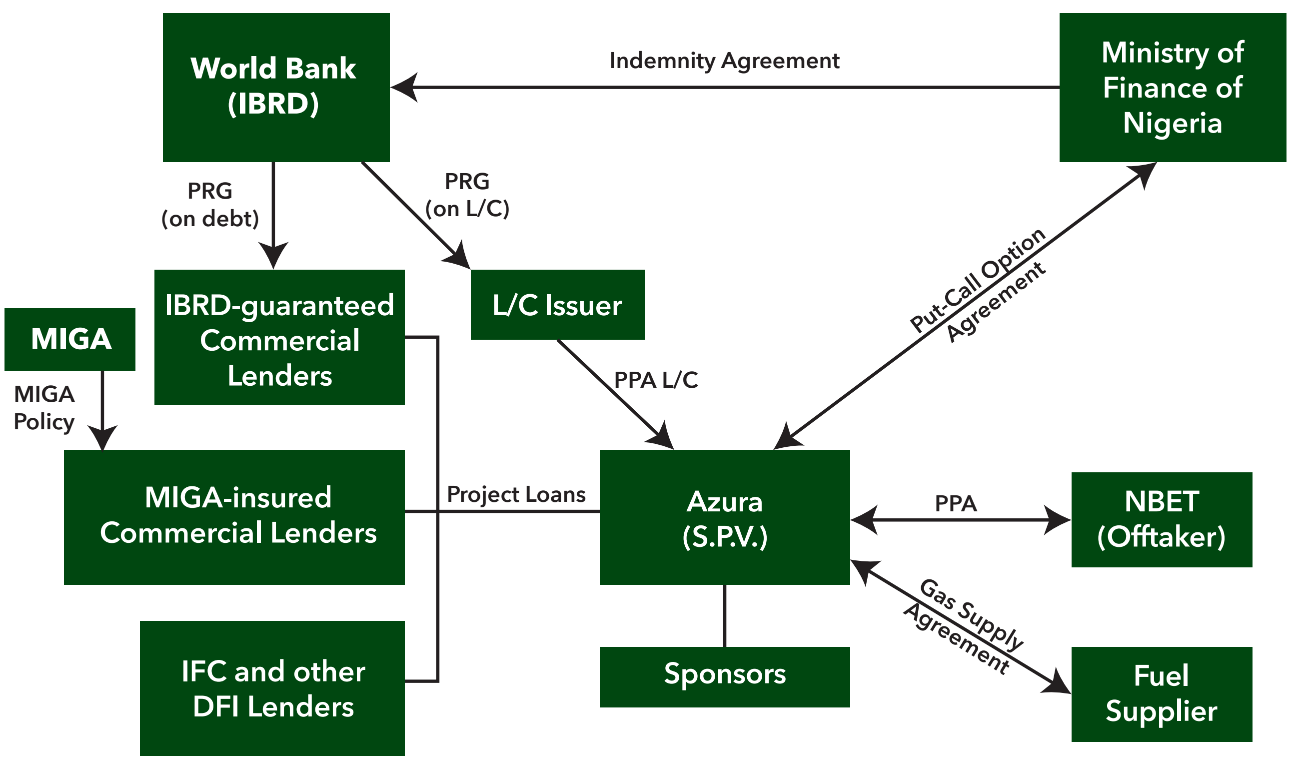
Such guarantees can now be issued not only in favor of private entities, but also to foreign public entities in an effort to promote cross-border, public-to-public operations.

As already alluded to, to avoid entangling the bank in the substance of any contractual dispute, bank guarantee policy requires that a project contract supported by a guarantee contain appropriate dispute resolution procedures and, if a dispute arises as to the government's obligations, then the bank's guarantee is triggered only after the government's liability has been determined in accordance with those procedures. The recent reforms have clarified that this latter limitation is subject to the caveat that, in some cases, payments under a guarantee can be triggered, notwithstanding an unresolved dispute, if there is a clear government payment obligation and adequate mechanisms exist to ensure that the government is reimbursed or otherwise properly compensated should a final decision determine that the amount of the partial risk guarantee payment exceeded the government's liability.

Also, the prior program clearly distinguished between partial risk guarantees and partial credit guarantees as separate products. The bank sees a potential for partial credit guarantees and partial risk guarantees to be used in a variety of creative hybrid guarantee structures to attract new sources of financing such as local currency loans and non-bank lenders such as sovereign and pension funds. To encourage innovative uses of World Bank guarantees, the bank no longer retains the distinction between partial credit guarantees and partial risk guarantees and intends rather to differentiate project-based guarantees by the nature of the risks that they propose to cover.

Finally, unlike partial risk guarantees, partial credit guarantees were not available to IDA countries. This restriction limited the opportunities to help IDA countries mobilize financing for critical development needs. Now, all forms of guarantees are available to IDA countries, except for those under high risk of debt distress. Considerations of fiscal sustainability are particularly important for IDA countries given their relatively limited experience with commercial sovereign borrowing and vulnerability to shocks. Thus, access to partial credit guarantees is limited to IDA countries with low or moderate risk of fiscal distress.

World Bank Payment and Loan Guarantees Nigeria – Azura Independent Power Project



World Bank, MIGA and IFC Compared

The World Bank guarantees play a different and yet complementary role to the support available through MIGA and IFC, sister agencies in the World Bank Group.

MIGA provides political risk insurance of cross-border direct investments for a wide range of offshore investors and sorts of projects. MIGA could not directly match the bank's guarantee of government payment obligations to a project company. Also, MIGA's breach of contract coverage, patterned after similar coverage available through the Overseas Private Investment Corporation, is typically restricted to standing behind arbitral awards. If a host government is not willing to submit to arbitration in a foreign tribunal (and some constitutions prohibit doing so), then MIGA coverage may not be an option.

The IFC provides credit guarantees, in addition to its traditional project loans, for private sector projects. Neither MIGA nor the IFC requires a host government indemnity against a loss.

Like IFC financing and MIGA insurance, World Bank guarantees also support private sector projects, but only by backstopping public sector obligations for which the member country is willing to provide an indemnity.

An example of natural convergence for World Bank support is the Azura power project in Nigeria, where IFC loans, MIGA political risk insurance and World Bank guarantees were all deployed together, as depicted in the preceding diagram.

The guarantees can now run in favor of more parties than just the lenders.

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deduct the same amount in the same year the holder reports income.

Some companies receiving warrants make an election under section 83(b) of the US tax code to report the value as income immediately upon receipt of the warrants without waiting until the warrants vest or are exercised in situations where the warrants have little value initially. When such an election is made, there is no need to report further income when the warrants vest or are exercised. The deduction for the company granting the warrants must match the amount and timing of the income, so there may be no deduction.

ANTI-BRIBERY efforts are expected to step up in the United States.

The US Department of Justice is hiring another 10 prosecutors for its unit that enforces the Foreign Corrupt Practices Act. This will double the size of that unit.

The Foreign Corrupt Practices Act makes it a crime for a US company, citizen or resident to offer anything of value to a foreign government official, political candidate, or employee of a state-owned company or international public organization in an effort to win or retain business. The US also prosecutes foreign companies for bribery outside the United States if the company paying the bribe has raised money in US capital markets.

Other countries are not working as hard as the United States to prevent cross-border bribery by their citizens, according to a report by TRACE International in March.

The United States had 126 investigations of potential bribery of foreign officials underway at the end of December, compared to a total of 125 investigations in the 26 other countries tracked in the survey. The US brought 16 enforcement actions in 2015 compared to a total of four in all the other countries.

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Impact on Investment

Most major infrastructure projects include the host government in one or more key roles.

The project economics may depend on the government standing behind the terms of the concession, an offtake agreement or an agreement to supply fuel or facilities. The government may have guaranteed performance or payment by offtakers or suppliers whose own credit ratings are too weak to support the financing for a project of the size proposed.

The guarantees can bridge concerns about a sovereign credit.

A perennial question for both project developers and lenders, when considering an emerging market infrastructure project, has been how to be able to take such host government undertakings seriously, particularly where the government in question lacks a track record of performing such obligations, either because such project structures are new to that country or its prior performance record is spotty.

The World Bank guarantee program squarely addresses such risks. In supporting the Hub power project in the 1990s, the World Bank determined that, though it could not lend to private projects, it could, with much developmental benefit, guarantee commercial loans to such a project against the specific risk that the host government might fail to perform its contractual undertakings in favor of the project or its investors.

Conventional political risk insurance coverage against expropriation conceived of insured projects as being private businesses apart from the government. In contrast, the partial risk guarantee was invented with public-private joint ventures in mind. As such, these guarantees — which have now also been offered by the Inter-American Development Bank, the European Bank for Reconstruction and Development, the Asian Development Bank, and the African Development Bank — fill a large gap in the fabric of effective project risk mitigation.

With its recent enhancements, the partial risk guarantee program seems to be coming into its own. In stark contrast to the generally slow rate of issuance of partial risk guarantees over the past two decades, dozens of applications are currently under review at the bank. While not all those will reach financial close, a substantial uptick in both demand for, and the supply of, World Bank guarantees in support of privately-developed infrastructure projects is evident. These numbers are consistent with the bank's plan for the enhanced guarantees program, which is to make its guarantees more easily available to developers, lenders and host governments.

The requirement of a host government indemnity will continue, so this product will still not fit every project. It will be appropriate only for those seen by host governments as being of such priority as to merit their entering into an indemnity agreement with the bank. For those priority projects, the new guarantee program could be a powerful tool for making important things happen. ◎

Environmental Update

Attorneys general from Massachusetts and the US Virgin Islands announced in late March that they are joining ongoing efforts by New York and California to investigate possible inconsistencies between corporate securities disclosures and what public companies concluded internally about the risks from climate change to company finances.

Last fall, New York Attorney General Eric Schneiderman took a number of actions suggesting there may be greater peril to companies in what they disclose, or fail to disclose, to investors about the potential effects of climate change on company bottom lines.

Then, Schneiderman accused coal behemoth Peabody Energy of violating state laws by making misleading statements to investors and the public about the financial risks it faced from climate change and potential regulatory responses. Peabody told shareholders that it is unable to predict the effects of environmental regulations despite internal company projections that the regulations could significantly reduce the value of its coal sales in the United States. Peabody agreed to revise its shareholder disclosures. (The company warned in March that it may have to file for bankruptcy.)

Around the time of the Peabody settlement, the New York attorney general also subpoenaed ExxonMobil to determine whether the company has made false statements to investors about climate change risks. California later joined in the investigation.

The investigation is focused on what ExxonMobil and possibly other companies knew about the financial risks and whether it is consistent with what they told shareholders. ExxonMobil helped to fund outside groups in the past that were working to dispute climate science at the same time as its in-house scientists were describing the possible consequences of climate change along with the areas of uncertainty.

ExxonMobil has said it is cooperating with the investigation, but said the accusations are based on the "preposterous claim" that it "reached definitive conclusions about anthropogenic climate change before the world's experts" and did not disclose them.

While the inquiry could be expanded to other energy companies or even trade organizations, none has been named.

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IN OTHER NEWS

MINOR MEMOS. More than half of House Republicans have co-sponsored a bill to "blow up" the US tax code at the end of 2019 in order to force Congress to start over . . . . The IRS wants comments by May 16 on tax issues that it should put on a priority guidance list to try to address over its next "business plan year" that runs from July 1, 2016 through June 30, 2017. The request for comments is in Notice 2016-26. An unusually large number of issues of interest to the project finance community are on the current business plan that runs through June 30. (See the September 2015 *NewsWire* starting on page 7.) Most have not been addressed yet and are likely to remain on the list for next year . . . . New partnership audit rules that take effect in 2018 will require some rewriting of partnership agreements and have the potential to complicate future sales of interests in existing partnerships, loans where a partnership is the borrower, and the allocation of risk and tax contest provisions in tax equity deals. The IRS is working on regulations to implement them and asked in Notice 2016-23 for comments by April 15 . . . . Many partnerships are expected to try to opt out of the new partnership audit rules. They would allow the IRS to collect any back taxes on audit from the partnership rather than have to chase each partner for its share. This opt-out election is not available if any of the partners is itself a partnership unless the IRS says otherwise in regulations. The IRS is not expected to be very generous in allowing opt-out elections. The Joint Committee on Taxation suggested in its "blue book" summarizing tax legislation enacted in 2015 that the opt-out election will also be unavailable, unless the IRS says otherwise, in cases where a partnership owns a project through a wholly-owned special-purpose limited liability company. This is a common ownership structure in the power industry. The blue book was released in March.

— contributed by Keith Martin in Washington

Environmental Update

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Lesser Prairie Chicken

A federal district court in Texas affirmed in late February its decision to overturn the listing of the lesser prairie chicken as "threatened" under the federal Endangered Species Act.

The court had previously found that the listing was arbitrary and capricious.

The Fish & Wildlife Service had asked the court to send the matter back to it for further consideration without nullifying the listing of the bird as threatened — an action that would have left the Endangered Species Act protections in place while the agency addressed the problems raised by the court. The court's ruling strips the lesser prairie chicken of those protections.

The court said the species does not face an imminent and substantial threat. It said that the easing of the western drought and the severe decline in oil production in areas where the species lives have left it less threatened. The court also found fault with the failure by the Fish & Wildlife Service to consider whether a conservation plan established before the agency's decision might be enough in lieu of listing the species as endangered.

The court also rejected a request by the Fish & Wildlife Service to limit the court's ruling just to the Permian Basin in west Texas and southeastern New Mexico. Therefore, the decision is at least temporary relief for developers, including the wind industry, across Colorado, Kansas, New Mexico, Oklahoma and Texas.

Although the lesser prairie chicken is no longer entitled to federal protection as an endangered species, uncertainty remains a significant concern for both developers and lenders.

The government is likely to appeal the decision or to consider a new listing for the species, possibly both. A new listing effort may already be underway.

Developers with projects in areas where the birds are found must weigh the risk that the species might be redesignated as an endangered species.

The case at issue is *Permian Basin Petroleum Association et al. v. US Department of Interior.*

A court said the lesser prairie chicken is not threatened, but the status could change.

Clean Power Plan

The Clean Power Plan remains in limbo, possibly until early 2018, to give first a US appeals court and then the US Supreme Court time to hear arguments about the plan.

The stay granted by the US Supreme Court in February came as a surprise. The late Justice Antonin Scalia was in the 5-4 majority that voted for the stay.

It is unusual for the high court to block federal regulations, particularly where, as here, a US court of appeals had just denied a similar request. The decision suggests that at least four of the remaining Supreme Court justices have concerns about the authority of the Environmental Protection Agency to implement the far-reaching regulatory changes contemplated by the plan.

The Clean Power Plan requires a 32% reduction in carbon dioxide emissions from most existing coal- and gas-fired power plants by 2030. Each state has been assigned individual carbon reductions and is required to submit an implementation plan

The Clean Power Plan may remain in limbo until early 2018.

demonstrating how it will achieve the reductions. The federal government will impose a federal plan in states that fail to submit their own plans or submit plans that fall short of what the Clean Power Plan requires.

The Clean Power Plan contains a detailed implementation schedule and several interim deadlines, including a September 2016 deadline for states to submit compliance plans. The September 2016 deadline has been suspended by the stay.

The Senate majority leader, Mitch McConnell (R-Kentucky), sent all the governors a letter in March urging them not to work on state plans to reduce carbon emissions. McConnell warned them "to carefully consider the significant economic and legal ramifications at stake before signing your states up to a plan that may well fall in court."

Opponents are urging EPA to defer the 2022 initial deadline to begin achieving emissions reductions for the same amount of time that the stay is maintained.

Oral arguments about the plan are scheduled in the US court of appeals in Washington on June 2 and 3. A decision is expected in October. It is virtually certain, regardless of the outcome, that the appeals court decision will be appealed to the Supreme Court. The Supreme Court would hear the case in 2017, but probably not issue a decision until early 2018.

It is hard to predict how the Supreme Court will ultimately resolve the issues, particularly in light of the recent death of Justice Scalia. A successor to Scalia is unlikely to be seated on the Supreme Court before the November 2016 presidential election. If the Supreme Court ends up with a 4-4 split in the case, that would leave any decision by the court of appeals in place.

States are deciding in the meantime whether it is prudent to continue work on preparing compliance plans. According to EPA, 25 states have indicated they will continue working informally with EPA on their own compliance plans. Another 20 states have said they have either suspended or are scaling back compliance efforts.

The Next Justice

Merrick Garland, whom President Obama has nominated to fill Scalia's seat on the court, has a judicial record that suggests he may vote to uphold the Clean Power Plan. Garland has tended to give deference to government agencies, rather than substitute his own views on policy, regardless of whether agency rules were written during a Republican or Democratic administration.

Garland is the chief judge of the US Court of Appeals for the District of Columbia circuit, which has exclusive jurisdiction to review regulations arising under a number of environmental statutes, including the Clean Air Act — the source of authority for the Clean Power Plan.

Garland is not on the three-judge panel that will decide the current challenge to the Clean Power Plan when the case is heard by his court.

Initial reaction to Garland's nomination from supporters of the Clean Power Plan has been favorable. SCOTUSblog.com said, after analyzing Garland's environmental decisions, that "Judge Garland has in a number of cases favored contested EPA regulations and actions when challenged by industry, and in other cases he has accepted challenges brought by environmental groups."

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Garland voted in 2014 to uphold EPA's hotly-contested MATS rule limiting mercury emissions from fossil fuel power plants.

According to UCLA law professor Ann Carlson, Garland "is almost always deferential to agency interpretations of statutes." Professor Carlson said his record "at least suggests he is likely to uphold the president's signature climate initiative, the Clean Power Plan."

Richard Lazarus, an environmental law scholar at Harvard University, said Garland is well-respected by environmental law practitioners and "doesn't come with any inherent skepticism about the federal government overreaching. In terms of looking for someone who would give a fair hearing [to the Clean Power Plan], he's a big shift from Scalia." ◎

— contributed by Andrew Skroback and Richard Waddington in Washington

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01-01 PF NewsWire April 2016

* Legal services in Poland are provided by Radzikowski, Szubielska i Wspólnicy sp.k., an independent law firm that is part of Chadbourne's international legal network.