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PROJECT FINANCE

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Solar Tax Equity Market: State of Play

Many US solar projects are financed in the tax equity market. Solar tax equity deal volume hit $4.5 billion in 2015, and is expected to increase in 2015 and 2016 as solar developers rush to complete projects before a 30% investment tax credit for solar equipment falls to 10% after 2016.

A panel of three prominent tax equity investors and finance experts at two of the largest solar rooftop companies talked at a solar finance workshop in New York in late February, organized by the Solar Energy Industries Association, about tax equity yields, current issues in deals, the tax bases being used to calculate tax benefits and other subjects. The panelists are Mit Buchanan, managing director at JPMorgan Capital Corporation, Angelin Baskaran, vice president on the global structured products desk at Morgan Stanley, George Revock, managing director and head of alternative energy and project finance at Capital One, Albert Luu, vice president for structured finance at SolarCity, and Jason Cavaliere, vice president for project finance at Sunrun. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Three main tax equity structures are in use currently in the solar market. They are sale-leasebacks, inverted leases and partnership flips. George Revock, does Capital One have a preference among the three and, if so, why?

MR. REVOCK: We prefer to use the partnership flip structure. It is a proven structure from a tax perspective, and it is also most trusted by the sponsors. We are happy to do

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INVERTED LEASES are getting attention from the Internal Revenue Service.

In an inverted lease, a developer leases a solar project to a tax equity investor and assigns the power purchase agreement or other customer agreement that is the source of revenue for the project. The tax equity investor collects the revenue and pays most of it to the developer as rent for use of the project.

The developer makes an election with the IRS to let the tax equity investor claim the investment tax credit on the project. The developer keeps the depreciation. Developers like inverted leases because IRS regulations let the investment credit be calculated on the fair market value of the project — rather than its cost — and the developer */ continued page 3*

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sale-leasebacks as well. Those are a prudent structure from a tax perspective. The one structure we are not looking at right now is the inverted or pass-through lease. We view inverted leases as having more tax risk. There is some guidance that may be adverse to that particular structure, and we prefer to pass on it until there is further clarification.

MR. MARTIN: Mit Buchanan, does JPMorgan have a preferred structure and, if so, why?

MS. BUCHANAN: While we have sale-leasebacks in our portfolio, our strong preference is to use a partnership structure. There are two main reasons. First, we like the fact that with a partnership structure, the developer has some skin in the game.

Second, we also like the fact that if there is underperformance, with the flip structure, the tax equity investor continues to receive an agreed share of cash available each year for distribution until it reaches the target yield, unlike a lease where the transaction goes into default. It is also nice that partnership flips are priced to reach the target yield in six to eight years while, in a lease transaction, the investor receives its yield over a 15- to 20-year term.

MR. MARTIN: Angelin Baskaran, does Morgan Stanley have a preference?

MS. BASKARAN: We do. We also prefer the partnership flip for the reasons cited and because we tend to be a pure-play tax equity investor. We like to be in for the tax benefits and minimize our cash exposure, and the partnership flip tends to be a friendly structure for that approach.

MR. MARTIN: Do you also do sale-leasebacks?

MS. BASKARAN: We do not. We have not done so for a while. We just find that it is a longer-dated exposure than we want. It is more balance-sheet intensive, and we believe sponsors are in a better position to bear residual risk.

MR. MARTIN: You heard George Revock say Capital One is not doing inverted leases because it considers them riskier than the other structures. Do you do inverted leases?

MS. BASKARAN: We do not. We are familiar with the structure because we have used it for historic tax credit deals, but we are waiting for additional guidance from the IRS about section 50(d) income before we use it in the solar sector.

MR. MARTIN: The section 50(d) income is the amount of income the lessee must report ratably over five years to offset part of the value of the investment tax credit.

MS. BASKARAN: That's right. The lessee must report income instead of reducing its tax basis in the assets by half the investment credit. It cannot reduce the basis because it does not own the assets.

MR. MARTIN: Mit Buchanan, coming back to you. You mentioned sale-leasebacks. You mentioned partnership flips. Does JPMorgan also do inverted leases?

MS. BUCHANAN: We do not.

MR. MARTIN: Let's move to the sponsors. Albert Luu, does SolarCity have a preferred tax equity structure?

MR. LUU: We are generally agnostic about the structure. Probably half our deals are partnership flips and half our deals are some variation of an inverted lease. We generally let the tax equity investors pick the structure, and if it raises the capital we need on palatable terms, that works for us.

MR. MARTIN: You did not mention sale-leasebacks. I believe there is a reason for that.

US solar tax equity deal volume hit $4.5 billion in 2014.

MR. LUU: Yes. It is more expensive in a sale-leaseback for the lessee to retain the assets long term. At the same time, we do not think lessors pay us enough at inception for the residual value after the lease ends. We want to be the long-term owners of these systems; we value a long-term relationship with the customer. We did a few sale-leasebacks in our early years, but we have not used the structure much since then. If someone were to offer us 4% or 5% money and assign a reasonable value at inception to the residual, then we would take another look.

Another challenge for the sale-leaseback is you are financing cash flows at higher yields than you can finance them in the debt market.

MR. MARTIN: Jason Cavaliere, which structure does Sunrun prefer?

MR. CAVALIERE: We prefer a structure that gives us the lowest cost of capital.

MR. MARTIN: Okay. Albert Luu, you heard George Revock say that he believes inverted leases carry greater tax risk. Are you indifferent to structure risk because it is borne by the tax equity investor?

MR. LUU: We are not the ones that bear the structure risks generally, but we are still fairly conservative when we think about structure risk.

Keep in mind that there are many variations of inverted leases. Some people are more comfortable with an overlapping ownership inverted lease where both the lessee and lessor are partnerships. The lessee is owned largely by the tax equity investor, and the lessor is a partnership between the sponsor and the lessee. Other people prefer what we refer to as a clean or simple lease structure, where the sponsor is the lessor and the tax equity investor is the lessee with no cross ownership.

Risk Allocation

MR. MARTIN: Mit Buchanan, how do the structures compare in how they allocate risks between the tax equity investor and the sponsor, and how much capital does each raise?

MS. BUCHANAN: People talk about a sale-leaseback as a form of 100% financing, since the sponsor is paid the fair market value of the assets by the tax equity investor. But it is really not.

MR. MARTIN: Because the sponsor must immediately prepay part of the rent to the tax equity investor.

MS. BUCHANAN: It is typical to see a rent prepayment on the order of up to 20%, so it is not 100% financing. Turning to the partnership flip, the tax equity raised in a solar deal is usually about 40% to 50% of total capital, but the percentage depends on the facts of the deal.

MR. MARTIN: And an inverted lease raises what percentage of the capital cost of a project? None of these tax equity investors does those, so Jason Cavaliere, what is the percentage for an inverted lease? */ continued page 4*

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gets back the project when the lease ends without having to pay anything for it.

Under IRS rules, the lessee must report half the investment credit as income ratably over five years.

If the lessee is a partnership, then the tax equity investor increases the basis that it has in its partnership interest by this income. This puts the investor in a position to deduct the income later as a loss by withdrawing from the partnership or selling its partnership interest.

The IRS is unsure whether such a loss is appropriate. It may issue guidance on the subject as early as the summer.

PRODUCTION TAX CREDITS for wind and geothermal projects remain at 2.3¢ a kilowatt hour in 2015, but moved up slightly from 1.1 to 1.2¢ a KWh for biomass, landfill gas, incremental hydroelectric and ocean energy projects, the IRS said in April.

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

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level in 2015 is 12.2688¢ a KWh. The IRS said there will not be any phase out in 2015 because contracted wind electricity prices are 4.50¢ a KWh going into the year, down from $4.85 the year before. It said it lacks data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $6.71 a ton in 2015. Refined coal is coal that has been treated with chemicals to make it less polluting than regular coal. The IRS said there will not be any phase out of refined coal credits in 2015. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2015 reference price is $57.64 a ton. A phase out would have started at $83.17 a ton.

Meanwhile, the IRS said at the end of March that it will no longer issue */ continued page 5*

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MR. CAVALIERE: It depends on the tenor of the lease. Some inverted leases with overlapping ownership monetize six, seven or eight years of cash flows and, therefore, raise a large share of the capital cost. We have one investor who prefers to monetize all 20 years of cash flows. That leads to an extremely high advance rate.

MR. MARTIN: So are we talking about 9%, 30%, 40%? How much?

The search for yield is bringing more tax equity investors into the market.

MR. CAVALIERE: For the 20 years, it would be approximately 70%.

MR. MARTIN: What is the bottom of the range?

MR. CAVALIERE: The bottom would be a pure tax-break partnership that would raise about 45% to 50%.

MR. MARTIN: Albert Luu, that sounds high to me. Have you seen lower?

MR. LUU: We have seen lower percentages in fixed-flip partnership transactions where the sponsor retains as much cash as possible. In those cases, the percentage might be something like 40%. I think in an inverted lease with a term of eight to 10 years and where the tax equity investor is keeping maybe 20% of the overall cash flow, the sponsor is probably raising between 35% and 40% of the project value.

MR. MARTIN: Angelin Baskaran, does Mit Buchanan's figure of 40% to 50% of the capital raised in a solar partnership flip sound like the right range?

MS. BASKARAN: I think it does. Those sound like the right numbers for a partnership flip with a preferred return and no deficit restoration obligation.

MR. MARTIN: George Revock, is the allocation of risks between the sponsor and tax equity investor the same across all three structures?

MR. REVOCK: The risk that the structure works to transfer the tax benefits is usually borne by the investors. The risk that the basis used to calculate tax benefits is too high is borne by the sponsor. There is a good trade around whether the depreciation deductions are properly calculated. In some deals, we see the investor take the risk that the depreciation deductions were properly calculated in the base case model. In some deals, the sponsor takes that risk.

MR. MARTIN: Albert Luu, do you think the risk allocation is the same across all three structures?

MR. LUU: Generally yes.

When you think about the inverted lease, the lessee really has to be in the business of sub-leasing the equipment or selling power. The transaction must be a true lease; it cannot be a financing arrangement. So I think you see the tax equity investor in such transactions take more operating risk, or it should take more operating risk in that structure versus a partnership flip where the partnership of the sponsor and tax equity investor is taking the operating risk.

Solar Deal Flow

MR. MARTIN: Mit Buchanan, where is most of the action today in the solar market? Is it in utility scale or rooftop?

MS. BUCHANAN: It depends. In 2013 through 2014, there was rapidly growing interest in the residential rooftop sector. It is a sector with a huge volume of business and a very small investor base. Toward the end of 2014 and now early 2015, there are some very sizeable utility-scale transactions that are coming to market. I think utility-scale transactions may be more dominant this year.

MR. MARTIN: George Revock, where do you think the action is?

MR. REVOCK: Keep in mind that projects must be in service by December 2016 to qualify for a 30% investment tax credit. At some point this year, investors will start to turn away from utility-scale projects with construction periods that are long enough to create risk the projects may not be completed in time. So maybe utility-scale projects will account for a significant share of the market for the first part of the year, but then the market will turn back to solar rooftop projects that are still capable of being installed before the credit expires.

MR. MARTIN: Angelin Baskaran, what is your view? More utility scale? More action in rooftop?

MS. BASKARAN: We see more action in the residential and small commercial and industrial projects, with residential being the dominant part. We saw a lot of utility-scale projects three years ago, and they largely went down the strategic route. They ended up not needing tax equity because they raised tax-efficient cash equity from strategic investors who could use the tax benefits. It would not surprise me to see interest pick up again in the utility-scale projects among strategic investors.

MR. MARTIN: Focusing still on our tax equity investors, will you invest in solar thermal projects? George Revock, I know you are in a power-tower project now, so your answer is yes. Mit Buchanan?

MS. BUCHANAN: We have actually done concentrating solar power, so yes.

MR. MARTIN: You did Nevada One, which was the first solar thermal project since the last SEGS projects in the early 1990's.

MS. BUCHANAN: Correct.

MR. MARTIN: Angelin Baskaran, will Morgan Stanley do solar thermal?

MS. BASKARAN: We have not done it yet, but we are open to it.

MR. MARTIN: I assume all three of you will do utility-scale solar PV projects, but what about commercial and industrial rooftop projects? Mit is nodding yes. Angelin is nodding yes. George Revock?

MR. REVOCK: We would do them as well, but we have not seen an opportunity yet.

MR. MARTIN: What about residential rooftop? Yes or no?

MR. REVOCK: Yes.

Key Metrics

MR. MARTIN: Let the record show that all three of our tax equity investors are nodding yes. Moving to our sponsors, what are current tax equity yields? Jason Cavaliere?

MR. CAVALIERE: Depends.

MR. MARTIN: You were allowed to give that answer when you were a tax equity investor. Now you are a sponsor. [Laughter]

MR. CAVALIERE: Well, we care mostly about the pre-tax yields rather than the after-tax yields. We try to push for as low a pre-tax yield as possible, whether it is zero or 2% or in some cases

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rulings about refined coal projects. The agency had been issuing rulings confirming that the processes taxpayers are using to treat coal lead to production of "refined coal," but had not been ruling on whether the transaction structures sponsors have been using with tax equity investors work to transfer tax credits. Jaime Park, chief of the IRS branch that handles the credit, said the decision to stop ruling was purely a resource issue. Congress has cut the IRS budget in each of the last five years. The agency is down 13,000 employees from 2010 and has a hiring freeze that prevents ruling branches from replacing any lawyers who leave. It is looking for ways to save on resources.

The announcement about the no-rulings policy is in Revenue Procedure 2015-29.

THE TREASURY has now won one and lost one lawsuit against it for shortfalls in Treasury cash grants.

The next trial is scheduled for May 23, and another 23 cases are in line behind it. Two new suits were filed in March and April.

All the cases were filed in the US Court of Federal Claims by owners of renewable energy projects who were paid smaller grants under the section 1603 program than the amounts for which they applied. Congress directed the Treasury to pay 30% of eligible basis in new wind, solar, geothermal, fuel cell and other renewable energy projects starting in 2009. The program has largely expired. However, solar projects that were under construction by December 2011 still qualify for grants if completed by the end of 2016. Many developers ended up being paid less than they thought they were entitled. Companies have up to six years after a grant was paid to file suit.

The government won the first case in January involving a biomass power plant whose owner applied for a cash grant of $2,711,311, but received only $943,754. The Treasury allocated the plant cost between the parts of the project that produce steam and

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negative. As for after-tax yields, we are seeing 8%, 9% or 10% for a unlevered structure up to low teens for a levered structure.

MR. MARTIN: On the pre-tax yield, what do you think is current market? Are most people insisting on 2%? Less? More?

MR. CAVALIERE: Most people are insisting on 2% for the entire term of the contracted cash flow of 20 years. That does not mean that they will have a 2% pre-tax yield on the flip date.

MR. MARTIN: Albert Luu, what are current yields from where you sit?

MR. LUU: Not low enough. [Laughter] I think there is too much focus on yields because the internal rates of return are quirky when you get a large portion of the return on investment in something like 30 to 150 days. We focus as a sponsor more on our overall cost of capital and the retained value of the project — the value to SolarCity after factoring in what goes to the tax equity investor.

The tax equity could earn a high yield, but if we are keeping most of the cash flows and we are able to borrow against the future cash flows in the debt market at 4% or 5%, that is probably a better deal than doing a sale-leaseback where we raise all the capital we need at a tax equity yield.

MR. MARTIN: I was going to ask what your metric is for assessing different proposals from tax equity investors, but you just said overall cost of capital and retained value. How do you do the calculation?

MR. LUU: There are the tangible financial metrics like our internal rate of return, what percentage of the cash the tax equity investor is taking and our retained value. Then there are intangible metrics like is it a partner we want to work with? Is the investor flexible on terms like FICO? Do we think this is a partner that will grow with our business and let us grow our business? These all go into the mix.

All of that said, we generally need capital to sustain our very rapid growth rate, so it is not like we are turning down capital too often. However, these metrics help us evaluate competing proposals and help us decide what terms to ask for in deals.

MR. MARTIN: Is there anybody you would turn down? Lyndon Rive, your CEO, said you need to raise $3 billion this year.

MR. LUU: I think the $3 billion number is probably all-in project costs. We have said publicly that we want to install 920 megawatts to one gigawatt this year. Apply some cost level to that and you get our 2015 project financing needs. The tax equity number will be a little lower than that. The rest will be filled out in debt.

We said on our latest earnings call on February 17 that we have roughly 590 megawatts of un-deployed tax equity. We have a lot of visibility as to what our 2015 year will look like in terms of where our financing will come from and the remaining deals we will have to do this year.

MR. MARTIN: Jason Cavaliere, John Eber from JPMorgan always tells me the fixation with yields is misplaced. The sponsor should look at an all-in cost of financing or its returns after the financing is taken into account. What is your key metric?

MR. CAVALIERE: That's exactly right. Our main financial metric is day-one cash proceeds after we combine tax equity with any debt we plan to raise. The next most important thing, echoing what Albert Luu just said, is flexibility to be able to grow our business as we would like to do, whether it is being able to offer customers prepaid leases or PPAs or allowing FICO scores to go down, say, to 650. Flexibility in deployment and timing are intangible metrics that are extremely important for an operating business.

Interest is growing among sponsors in combining tax equity with back-levered debt.

MR. MARTIN: Returning to the tax equity investors, George Revock, how many years out do you price to reach yield in a partnership flip transaction in the solar market? The projects qualify for investment tax credits.

MR. REVOCK: Usually in six to eight years to reach the flip yield, but, technically, we are looking at 20 years for a typical underlying contract period.

MR. MARTIN: In other words, you have two different yields. You have one yield that you try to reach in six to eight years and, after that yield is reached, you flip down to a 5% interest. You have a different yield you are trying to reach by year 20, and what is it?

MR. REVOCK: We look for a slightly higher yield by year 20, but it is more of a pre-tax yield.

MR. MARTIN: Mit Buchanan, do you price to reach yield in solar deals in six to eight years?

MS. BUCHANAN: We usually price to reach yield in 6 1/2 to eight years.

MR. MARTIN: Angelin Baskaran, same thing at Morgan Stanley?

MS. BASKARAN: We tend to be on the shorter side, so six years is our average.

"Market" Terms

MR. MARTIN: Next subject, what is current "market" on a number of terms? George Revock says basis risk is borne by the sponsor. Sponsors, do you agree?

MR. LUU: Yes.

MR. CAVALIERE: Generally, yes.

MR. MARTIN: Is there any evolution in the market in how basis risk is split?

MR. LUU: We would like to move back to how basis risk was handled before 2009 when the Treasury cash grant program started, but the market has not really moved in that direction yet. We have spent considerable time working through the appraisal process in determining the fair market value of these projects. The appraisals have been reviewed by numerous law firms. We would not want to be in a situation where we are taking basis risks, but not having input in the appraisal process.

MR. MARTIN: So investors have to use your appraiser. Mit Buchanan, how large a deficit restoration obligation are investors willing to agree to in the current market?

MS. BUCHANAN: We look at the downside scenario and how quickly any DRO to which we agree will reverse. It is hard to give you a percentage, because it really turns on the particular transaction. Our stress case is a P95 case.

MR. MARTIN: One used to see deficit restoration obligations in the past as high as 20% to 23% of the capital the investor put into the deal. More recently, the DROs have been in the single digits, even in low single digits. Is that fair? */ continued page 8*

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electricity and paid a grant only on the part that produces electricity. The court gave "considerable weight" to the Treasury's view of how to administer the program, but stopped short of giving the Treasury total discretion. (For earlier coverage, see the February 2015 *NewsWire* starting on page 7.)

The case that the taxpayer won involved two fuel cell projects at municipal wastewater treatment facilities. The fuel cells use methane gas produced by putting sewage sludge through anaerobic digesters. The gas must be cleaned before it can be used in the fuel cells. The municipalities own the digesters and supply the methane to the fuel cell owners. The fuel owners own gas conditioning equipment. The Treasury paid grants on the fuel cell assemblies, but not the gas conditioning equipment. The issue was what the US tax code means by "fuel cell power plant" — the equipment on which an investment tax credit can be claimed and on which, by extension, a Treasury cash grant would be paid. The tax code defines it as "an integrated system comprised of a fuel cell stack assembly and associated balance of plant components which converts a fuel into electricity using electrochemical means."

The court said the gas conditioning equipment is integral to the fuel cell and, as such, should be treated as part of the power plant. The court took 117 pages to explain its decision. The case is *RP1 Fuel Cell, LLC and UTS SJ-1, LLC v. United States*. The opinion was released on March 31.

Edward Settle, a National Renewable Energy Laboratory official involved with reviewing grant applications, testified at trial that the Treasury has processed 100,000 grant applications, but has another 100,000 to go.

Two new suits were filed in the last month. The owner of a large solar parabolic trough power plant filed suit in March over a $5.87 million grant shortfall. The dispute centers around whether various types of spending on the project qualify as basis in the solar equipment or in other assets that are not part of the solar generating equipment. For example, the */ continued page 9*

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MS. BASKARAN: I think that's right. To highlight Mit's point, you ask whether you can see yourself realistically getting out of the deficit, and the way deals are structured right now, it is difficult to climb out of a big deficit.

MR. MARTIN: What is current "market" on lender forbearance where debt is ahead of the tax equity in the capital structure? Must the lenders agree to forbear from taking the project assets after a default in order to give the tax equity investors time to reach their yield and, if so, for how long?

MR. REVOCK: Forbearance is usually required for at least the recapture period for the investment tax credit. During that period, the lenders can foreclose on the sponsor interest, but they cannot take the assets and push out the tax equity investor.

MR. MARTIN: That may be more aspirational than what people are actually getting in the market, right?

MS. BUCHANAN: No, I would not say that.

MR. MARTIN: Albert Luu and Jason Cavaliere, you are both smiling.

MR. CAVALIERE: I was smiling during the discussion about the DRO because a lot of our deals have DROs of up to 30% to 35% of the tax equity investment.

MR. MARTIN: What about a sponsor call option when the sponsor can buy back tax equity investor's interest in the project or portfolio? Are such options always at fair market value? Do you see many fixed-price purchase options? Are the options at the greater of fair market value and a fixed price?

MS. BASKARAN: The sponsor call option in partnership flip transactions tends to be the greater of fair market value and the amount needed to get us to our target yield.

MR. MARTIN: That is for an option exercised before the flip. If the option is exercised after the flip, the price is simply fair market value determined at time of exercise?

MS. BASKARAN: That's correct.

MR. MARTIN: George Revock, I know you use a greater-of formula, even after the flip. What is your formula?

MR. REVOCK: It is a three-pronged formula: the greater of fair market value, the amount needed to get to the all-in yield and the amount needed to avoid a book loss on sale.

MR. MARTIN: The all-in yield means the 20-year yield, not the flip yield at year six or eight?

MR. REVOCK: Yes. For purposes of illustration, let's call the flip yield 8% and the full-term yield at year 20 is 9%. We will work to preserve that 9% because the residual is worth something. We use the hypothetical liquidation book value method to value our interest. If we would suffer a book loss were the sponsor to buy our interest at fair market value, then we will need a higher price to avoid having to report a book loss.

MR. MARTIN: Mit Buchanan, let's move to developer fees. What mark up by the sponsor is tolerable?

MS. BUCHANAN: We work closely with our tax counsel. We read the appraisal carefully to make sure the reasoning is credible. We might feel comfortable with an appraised value above actual cost to construct on the order of 10% to 15%, but the actual number depends on the facts of the particular case.

MR. REVOCK: There may be a higher markup when dealing with the manufacturer or the developer than in a secondary market transaction. We spend a lot of time understanding the appraisal and making sure whatever number is reported is credible.

MS. BUCHANAN: Sometimes the mark up depends on the degree of vertical integration of the developer. The fact that the developer plays more roles in the transaction might justify a higher mark up.

MR. MARTIN: How is risk that the law will change allocated between the sponsor and the tax equity investor? There is talk in Congress about possible corporate tax reform.

MS. BASKARAN: Are you asking about post-funding risk that the law will change or during the period between commitment and funding?

MR. MARTIN: Post-funding.

MS. BASKARAN: I think the only thing that has changed recently is we have been pushing back on sponsors to take risk that the depreciation method will change. Solar projects are depreciated over five years on an accelerated basis. There was a proposal in the Senate Finance Committee a couple years ago to require power projects to be depreciated on a straight-line basis over a longer period. Since then, we have pushed back in all of our deals for the sponsor to take the risk that depreciation has been calculated properly. I think that is the only recent change.

MR. MARTIN: Does anyone see any different risk allocation for change in law in the current market?

MS. BUCHANAN: That is something that is highly negotiated. The risk allocation varies from one deal to the next.

MR. MARTIN: Let me go back to the sponsors. What other issues do you think are currently in play in tax equity negotiations?

MR. CAVALIERE: One of the biggest issues is the mechanism for payment of tax indemnities. Years ago, any cash that would otherwise be distributed to the sponsor would be diverted to the tax equity investor to cover any indemnities. That is not debt friendly at all.

MR. MARTIN: It is not yield co friendly either.

MR. CAVALIERE: True. In the last partnership we did, there was no blanket cash sweep. We agreed to a negotiated percentage of cash that might be diverted. The percentage was low enough so that there is no risk of putting debt service on any back-leveraged debt in jeopardy.

MR. MARTIN: What cash sharing ratio do you tend to see today in the market? Is it 40% to the sponsor and 60% to the tax equity investors? 50/50?

MR. CAVALIERE: Usually 50/50, meaning that whatever the cash allocation is originally may go up by half of that if there is an event requiring payment of an indemnity. Thus, a 60% cash share for the investor might go to 80% until the indemnity is paid.

MR. MARTIN: Albert Luu, what other issues do you see in play?

MR. LUU: We have only seen cash sweeps to cover indemnity payments in the last year to year and a half. We spend a lot of time to ensure the structure leaves room for back-leveraged debt. We are a public company. There is a SolarCity guarantee of any indemnity obligation. We spend a lot of time educating investors that they should really look to that guarantee for payment of the indemnity rather than sweep distributable cash within the partnership.

The scope of the fixed tax assumptions in partnership flip transactions is another subject that is in play currently in the market. The fixed tax assumptions used to be a standard list of five or six things. There is more negotiation today around the fixed tax assumption dealing with depreciation and perhaps other changes in law. The market is pretty well set that the investor bears structure risks like whether the investor is a partner and the transaction has economic substance.

Another thing that we spend a lot of time negotiating is tranching constraints. We are an operating company and we need as few constraints as possible on how we deploy our systems. One of the reasons investors put money into residential solar deals is because they get risk diversification by owning a pool of systems with thousands of customers. They like to have a good mix across the country. But some investors have wanted their portfolios built around certain zip code mixes. That makes it tough for us to run our company, so we spend a lot of time with them explaining that they do not need this and will get a good mix because we operate in 15 states today. / *continued page 10*

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Treasury was unwilling to treat as part of the solar equipment two natural gas-fired auxiliary boilers that supply steam to the heat exchangers to prevent the heat exchange fluid from freezing at night, a 16-foot high wind wall that protects the solar mirrors and tubes from high winds and a groundwater well whose water is used to wash the mirrors and also to supply water to plant staff for drinking, showers, sinks and toilets.

In early April, MeadWestvaco, a paper company, filed suit over a grant paid on a new biomass boiler and 74-megawatt steam turbine that it put in service at a paper mill in Covington, Virginia in November 2013. The company treated 98.4% of the plant cost as eligible spending and applied for a grant of $85.9 million, but was paid only $38.9 million. The Treasury divided the project cost between the parts of the project that produce steam and electricity and paid a grant on the 48.8% of the project that it said was the cost of the electric generating equipment. Some of the steam is used to heat feedwater to make the power cycle more efficient. Other steam is sent to the mill for use in drying paper and other applications. The company argues that since all the steam is distilled into water in condensers and fed back into the boiler, the steam is an intermediate step to generating electricity.

Meanwhile, the Treasury inspector general is still writing up results from Treasury cash grant audits in 2010 and recommending that amounts be repaid to the Treasury. One recent report dealt with a grant paid in 2009. The inspector general recommended in it that a wind developer repay the Treasury roughly $1.5 million of a $114 million grant, or about 1.3% of the total grant paid.

> *The inspector general visited some grant recipients in the period after grants first started being paid as a check on how well Treasury officials were administering the program. The inspector general team were not tax experts. The grant office is free to accept or reject the recommendations.*

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MR. MARTIN: The zip code is a proxy for a high FICO score?

MR. LUU: Partly. It is also a way to ensure they have certain geographic diversification.

MR. MARTIN: Angelin Baskaran, are there other issues besides the list we discussed that take up time in deals?

MS. BASKARAN: I think they are driven primarily by the interest among sponsors in leaving room for back leverage. The cash sweep on indemnities is one such issue. Another issue related to back leverage is who is a qualified transferee. We spend a lot of time thinking through what happens if the back-leveraged lenders foreclose on the sponsor interest. How do we ensure an experienced operator can be found in such a situation to take over management of the solar portfolio?

MR. MARTIN: How important is it to have a back-up service provider when you have a company like SolarCity or Sunrun as the sponsor? When do you insist that someone have another servicer waiting in the wings?

MS. BUCHANAN: We universally require a backup servicer.

MS. BASKARAN: We require that also.

MR. MARTIN: Even for companies with national brands, like these two?

MR. REVOCK: Our credit card business is required to have a back-up servicer, so we figure it is a reasonable thing to ask of solar rooftop companies.

MR. MARTIN: Albert Luu, have you ever arranged for a backup servicer? Do you hire Sunrun? [Laughter]

MR. LUU: Jason can tell us whether he is available to climb on rooftops. We both will have to look into backup servicers for our securitizations. I do not think the requirement is to find a company that can actually get on the rooftop. You are looking for a company that can step into the administrative role and contract out the actual O&M services.

Basis Per Watt

MR. MARTIN: Mit Buchanan, where do you think basis is per watt currently in the solar rooftop market?

MS. BUCHANAN: There is a range, and it varies depending on whether it is residential or commercial and industrial, and it also varies by state. If you look at C&I, I think that you can see numbers in the $3 range.

MR. MARTIN: Between $3 and $4 dollars or right around $3?

MS. BUCHANAN: Between $3 and $3.50, but once again, it varies by state and circumstance. For example, there may be some systems that have above-average installation costs.

MR. MARTIN: In Hawaii, for example.

MS. BUCHANAN: For residential solar, I think the numbers are higher than that. For utility-scale, the numbers are more likely to be in the $2 to $2.50 range. But once again, these figures are not cast in stone. You have to look at the appraisal and the facts and circumstances around the installation.

MR. MARTIN: If someone comes to you with a portfolio of small utility-scale projects with a basis of $3.50 a watt, do you say, "Sorry, we are not interested. We are not prepared to pay more than $2.50 a watt."

MS. BUCHANAN: I would ask why the number is so high. I would like to look at the detail around it and see what the appraiser says.

MR. MARTIN: George Revock or Angelin Baskaran, do the ranges that Mit Buchanan just gave us sound right to you?

MR. REVOCK: Yes, I think those are pretty fair.

MS. BUCHANAN: I didn't give you a figure for residential solar.

MR. MARTIN: Please do, since residential solar is a large part of the market.

MS. BUCHANAN: I was focused on C&I. I would put a slightly different rate on residential systems.

MR. MARTIN: And the number is?

MS. BUCHANAN: A little bit higher than $3.50. How about that?

MR. REVOCK: The figures for

Tax equity investors are claiming bases of $3 to $3.50 a watt for commercial and industrial solar installations.

residential solar really turn on the location. The figures for New Jersey are different than Arizona and California. I think you can see a range of up to 20%, maybe even more, among the states. The figure might also vary depending on the local regulatory regime and whether the local utility is fighting net metering, what changes are expected in local power rates, and similar factors.

MS. BASKARAN: It is definitely geographically sensitive. We have closed on portfolios of from the low $4-a-watt range to the mid-$6 range in residential solar, and the differences are largely driven by location.

The choice of panels is also a huge sensitivity factor. The panel manufacturer, its financial wherewithal and any performance guarantees that come with the panels are all value drivers. So we really tear apart appraisals. We need to feel comfortable that the appraiser has done a thoughtful analysis, the conclusions are well defended and there has been a sensible weighting of the various methodologies that can be used to arrive at value.

MR. MARTIN: When you say $4 to $6.50, I assume that was some time ago, maybe in 2009 or 2010?

MS. BASKARAN: It was within the last couple years.

MR. MARTIN: Albert Luu, what are current basis figures for C&I and residential rooftop installations?

MR. LUU: There is not a wide range between one sponsor and the next in the residential market. The current numbers usually start with a 4, and there are some numbers in the $5 range. It really depends on the state and your installation costs in that state.

MR. MARTIN: Jason Cavaliere?

MR. CAVALIERE: I agree with Albert. Hawaii is a perfect example of this. It is by far the most expensive state in which to install solar. It would not surprise me if there are still some systems in Hawaii with bases in the $6 range. I have not looked at it recently, but Hawaii would definitely be at least in the $5 range.

MR. MARTIN: Bases are highest in Hawaii. In which state are they the lowest and what bases are being claimed currently in that state?

MR. CAVALIERE: I would say low 4s.

MR. MARTIN: In which state?

MR. CAVALIERE: Arizona is one of the lower ones.

Merchant Projects

MR. MARTIN: Back to the investors. George Revock, will you do merchant utility-scale solar projects / *continued page 12*

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IN OTHER NEWS

OUTPUT FROM WIND FARMS in the western US during the first quarter 2015 was off by as much as 50% from forecasts, possibly due to a warmer-than-average winter, according to a report in *North American Windpower*. Over- or underperformance can last years. However, wind speeds were 5% to 10%, and in some cases as high as 20%, above normal in Montana, the Dakotas, Minnesota and Nebraska.

OFFSHORE WIND FARMS are used in the United States for tax purposes if the electricity is used in the United States, the IRS said in a private letter ruling.

The agency analyzed the place of use of a wind farm that a developer planned to build five to 11 miles offshore.

Equipment used in the United States qualifies for more generous tax benefits than equipment "used predominantly outside the United States." The US treated its boundaries as extending three miles offshore from 1793 until President Reagan declared in 1988 that the US boundary extends 12 nautical miles out to sea, following the lead of 104 other countries that had already claimed jurisdiction to 12 miles offshore. However, it remains unclear what effect the Reagan proclamation had on various domestic laws, including the US tax laws.

In this case, the project was potentially physically outside the United States.

However, rather than try to settle where the US border ends for tax purposes, the IRS relied on a "functional use test." All of the electricity from the project would be sold to two utilities on the US mainland. Since the functional use of the project is to supply electricity for consumption in the United States, the project should be considered used in the United States, the IRS said.

The ruling is Private Letter Ruling 201510038. A redacted version was made public in March.

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and, if so, what do you need to see?

MR. REVOCK: We have not done so yet. I think they would be tough for us to do at this point. We would probably require at least a 10-year hedge. For a merchant wind farm, the hedge would probably have to be a little longer than that, perhaps 12 to 13 years to provide a safety margin in case we do not reach the target yield by the time the production tax credits expire after year 10. Solar deals are priced to a shorter flip period. Therefore, I am guessing a 10-year hedge would be enough.

MR. MARTIN: Mit Buchanan, merchant solar projects?

MS. BUCHANAN: That's why it is not a matter of whether we will do merchant projects. It is a question of where best to deploy capital given all the opportunities the market has to offer. There are easier solar transactions to do. If we want to get money out the door sooner versus later, a solar merchant deal would be a lower priority, but that does not mean we will not do them.

For utility-scale, bases are more likely to be in the $2 to $2.50 range.

MR. MARTIN: Angelin Baskaran?

MS. BASKARAN: We have not seen a merchant deal on offer. I think we would be very interested in looking at deals where they could come up with a hedge product, even if it is in the short-dated six- or seven-year range.

MR. MARTIN: Mit Buchanan, if I am not mistaken, JPMorgan has done merchant wind. You just have not seen merchant solar.

MS. BUCHANAN: That's why it is not a matter of whether we will do merchant projects. It is a question of where best to deploy capital given all the opportunities on offer. There are easier transactions to do. If we want to get money out the door sooner versus later, merchant deals would be a lower priority, but that does not mean we will not do them.

MR. MARTIN: Angelin Baskaran, is Morgan Stanley still offering power hedges?

MS. BASKARAN: We are. We have done quite a bit of that in the wind space over the last couple years, and we are certainly proactively looking to do more in wind as well as starting to do some in solar where the economics align.

MR. MARTIN: In just particular markets? PJM, ERCOT, New England ISO, where?

MS. BASKARAN: We are open to all them. We are happy to talk to sponsors about their projects.

Other Trends

MR. MARTIN: Still sticking with the tax equity investors, have you seen a trend lately of some tax equity investors who are interested solely in depreciation, perhaps as a way of spreading a small amount of tax capacity across a larger number of deals? [Pause] I see frowns, so let me ask the sponsors.

MR. CAVALIERE: I have not, and we would not be interested in pursuing that. We need to do something with the tax credit.

MR. MARTIN: Albert Luu, how common are tax audits in this area?

MR. LUU: Some deals are under audit. Some investors participate in the CAP program where they are under continuous audit by the IRS, so their transactions are reviewed sooner than others. We disclosed that a couple of our funds have been audited.

MR. MARTIN: What issues are coming up on audit?

MR. LUU: The main focus is around fair market value. What is the right number for these systems, especially in the residential space where people look at the direct cost of the system and then at the overhead associated with building that number of systems.

MR. MARTIN: Jason Cavaliere, how common are IRS audits and what issues are being raised in them?

MR. CAVALIERE: There are a few audits going on, and I agree with Albert. The main focus seems to be on fair market value. To my knowledge, I have not heard of any adjustments. The IRS agents are trying mainly to understand the process.

MR. MARTIN: Do the audits appear to be coordinated?

MR. CAVALIERE: Not to my knowledge.

MR. REVOCK: There seems to be a lot of consistency with how basis issues are handled under the Treasury cash grant program.

MR. MARTIN: Are you aware of any IRS audits as opposed to disputes with the Treasury?

MR. REVOCK: None to my knowledge.

MR. MARTIN: Mit Buchanan, are you aware of any audits?

MS. BUCHANAN: I am not.

MR. MARTIN: Angelin?

MS. BASKARAN: No.

MR. MARTIN: Turning to the section 1603 program, Albert Luu, is SolarCity still relying on Treasury cash grants or have you moved entirely to investment credits?

MR. LUU: We moved some time ago to investment tax credits. We got off the Treasury cash grant program as soon as we could.

MR. CAVALIERE: Jason Cavaliere, same story at Sunrun?

MR. CAVALIERE: Yes.

MR. MARTIN: Tax equity investors, are you aware of anyone who is still pursuing Treasury cash grants?

MR. REVOCK: We are.

MR. MARTIN: I believe you have in mind at least one large utility-scale project. Coming back to the sponsors, why did you get off the program?

MR. LUU: We filed suit against the Treasury over some shortfalls in what we were paid compared to the amounts for which we applied. The challenge with that program was it was well intended. It was supposed to provide capital when there was no capital in the marketplace for renewable energy companies. It was supposed to look and feel a lot like the investment tax credit, but the actual processes leading to grant payments did not end up working that way.

I do not think the Treasury was prepared for the massive volume of residential submissions it had to handle. This led to longer lag times to be paid grants than some of our investors were expecting.

Tax Equity Volume

MR. MARTIN: Mit Buchanan, you offered by e-mail some data on the size of the tax equity market for solar in 2014.

MS. BUCHANAN: For 2014, about $10.1 billion of tax equity was raised across both wind and solar. Wind exceeded solar by just a hair: $5.6 billion versus $4.5 billion.

MR. MARTIN: And that was with how many active tax equity investors? / continued page 14

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SOLAR ROOFTOP CUSTOMERS are choosing in large numbers to make direct purchases of solar systems rather than sign long-term leases or power contracts.

According to a UBS research report in March, EnergySage.com, an on-line platform, estimates that 70% to 75% of customers end up borrowing to finance direct purchases after comparing direct purchases to solar leases and PPAs. SunPower Corporation reported in a fourth quarter release that about two thirds of its customers choose direct purchases.

UBS says solar rooftop companies are not passing through falling solar panel prices fully to customers under leases and PPAs since pricing under such contracts is a percentage of savings from utility bills. It says the cost of a direct purchase was close to $5 a watt three years ago, but has fallen to the mid-$3 range in 2015. System costs vary significantly by state. The following are current average costs for customer-owned systems: California $3.75, Arizona $3.45, Colorado $3.75, Massachusetts $4.10, New York $3.95, North Carolina $3.75 and Texas $3.20.

Some solar companies are rolling out long-term installment sale contracts as a form of financing for direct purchases for customers who do not want to lease or sign PPAs. The installment sale contracts can run as long as 30 years.

However, the scale could tip back in favor of leases and PPAs if Congress extends the 30% investment tax credit for solar equipment put to business use while letting a similar residential credit lapse for homeowners who own their systems. Both credits are currently scheduled to expire at the end of 2016.

Meanwhile, the battle between solar rooftop companies and utilities took a new turn in late March as a prominent solar company filed suit against the Salt River Project, an Arizona utility, accusing the utility of violating federal and state antitrust laws by imposing distribution charges of $32.44 to $57.88 a month on customers who install rooftop solar systems plus demand charges on the kilowatt hours each / continued page 15

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MS. BUCHANAN: We counted 28 tax equity investors in 2014, of which 15 were prepared to do both wind and solar. There are 25 that will do solar. We are aware of three or four more investors that are still in their approval processes in terms of entering the market.

MR. MARTIN: JPMorgan worked for a long time to try to develop a secondary market in tax equity or at least to persuade other companies to invest alongside you. Is there much of a secondary market?

MS. BUCHANAN: There is a core group of investors whose investment criteria we know pretty well who can be pulled in to help cover a transaction.

MR. MARTIN: There seemed to have been almost 50% more tax equity investors in 2014 than 2013, ironically as the tax benefits are running out. To what do any of you attribute that?

MS. BASKARAN: The low-rate environment. It is pushing people to be creative and maybe look at things that have less-than-ideal accounting treatment or more complex structures. People are really looking for yield right now, and tax equity provides it.

MR. MARTIN: Does anyone expect equivalent growth — another 50% increase —in 2015? Albert Luu, you have been out searching.

MR. LUU: I don't know what the growth number will be, but there will be more tax equity investors in 2015 than in 2014 because there is more demand for tax equity and the investor base has been growing.

MR. MARTIN: The economy is growing, and corporations have more profits and more room for tax shield.

MR. LUU: There is definitely a growing potential tax base. It is just a long sales cycle to educate new investors who come into these deals, but once they get their arms around it, these are very attractive investments. When we look at our pool of financiers, everyone with whom we have done a deal comes back for follow-on transactions.

MR. CAVALIERE: Another factor that may be pulling more capital is potential investors can see the growth of the industry itself will not constrain how much capital they can deploy.

MR. MARTIN: Any questions from the audience?

MR. HUNTER: Chris Hunter with Brightfield Energy. I am curious to hear from the sponsors. If the investment tax credit steps down from 30% to 10% in January 2017, do you continue to raise tax equity against a 10% investment credit and depreciation or do you move, for projects in certain markets, to financing on an all-cash basis?

MR. CAVALIERE: We would definitely try to continue to raise tax equity against the 10% investment credit. The credit would be a third of the original value, but it is value that we would not want to leave on the table.

MR. MARTIN: So the sponsors are interested. What about the tax equity investors? This is your livelihood. You stay in the market, right?

MR. REVOCK: Presumably yes.

MR. MARTIN: Another audience question.

MR. GOTA: Luis Gota from New Energy Corporation. What are your thoughts about the Puerto Rican market?

MR. CAVALIERE: The biggest issue I see in the Puerto Rican market is risk of regulatory change. The net metering rules and the other laws that are necessary for this product to work face a high risk of change over the 20-year term of any customer agreement, and the risk is not something that you can quantify.

For those reasons, we looked at Puerto Rico, but decided against entering that market, at least with a power purchase agreement or lease model. It is a perfectly good market in which to make direct sales of systems, and that is something that we may do in the future.

MR. MARTIN: Albert Luu, SolarCity is in Puerto Rico, right?

MR. LUU: We have done some work on the commercial side, but I agree with everything Jason said. It is an island market, so the economics are great, but the uncertain regulatory environment makes it a very tough market for a 20-year product like a solar PPA or lease.

MR. MARTIN: Does anyone foresee pure-play solar rooftop companies forming yield cos or is use of that structure misplaced in the solar rooftop market? Solar rooftop companies do not have as pressing a need as utility-scale developers to separate operating projects from development pipelines. They do not have as long a development cycle.

MS. BASKARAN: I think rooftop solar could be a valuable element of diversification to yield cos as a source of cash flow, but I don't know that a rooftop-solar-only yield co makes sense. ◎

chadbourne

The Emerging African Market

by Lido Fontana, in Johannesburg

The opportunities for independent power producers in southern Africa are growing, but it is a complicated picture.

The constant rhetoric of "Africa Rising" appears plausible, but it very much depends on where in Africa one is referring and whether the political will exists both now and for the long term to ensure the good progress that is being made continues well into the future.

Big Picture

McKinsey & Company said in a recent report on the potential growth of the sub-Saharan electricity sector that by 2040 electricity consumption in the region is likely to grow from total current demand of less than Brazil to a level equal to today's consumption in India and all of Latin America combined.

Trends that make this a plausible forecast are significant urbanization and population growth that has taken place over the last few decades coupled with aging and inadequate infrastructure. While many challenges in the sub-Saharan power industry remain, progress is being made. Decisive action is being taken by several sub-Saharan African countries, in addition to a number of international initiatives which are supporting this growing movement for change.

From South Africa's internationally-praised renewable independent power program, which has attracted significant foreign investment, to Nigeria's privatization initiative which is creating a new competitive power market, sub-Saharan countries are initiating programs for change. Such efforts are being complemented by the likes of Power Africa, which was launched by President Barack Obama in 2013.

China's omnipresence in Africa also cannot be ignored. According to McKinsey & Company, direct investment from China has risen dramatically over the past 20 years. In 1996, Chinese direct investment was only $56 million. By 2005, this had jumped nearly 30 times, to $1.5 billion. Just six years later, the total was $15 billion. About 65% of this is in sub-Saharan Africa, of which just over a third goes directly into the energy sector.

Power Africa, which looks to work with African governments, the private sector and other partners such as the World Bank and African Development Bank, is currently / continued page 16

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customer uses during its most intensive 30-minute peak period each month. The demand charges are expected to add another $30 to $125 a month, depending on the season. Salt River is also reducing the amount it pays for electricity through net metering.

The utility is not subject to federal or state regulation over its retail rates.

The solar company says the charges amount to $600 a year for the typical solar customer and represent a 65% increase in such customer's utility bills. The utility approved the new rates in late February. It increased rates for other residential customers at the same time by an average of 3.98%. Applications for new solar installations have fallen by 96% since the charges were imposed. The solar company has 7,000 customers in the Salt River service territory. It was averaging 400 new installations in the six months before the new charges were imposed.

The complaint says the utility is violating antitrust laws by "using its market power to exclude competition by punishing customers who deal with competitors." The case is in the federal district court in Arizona. A jury trial has been requested.

MEXICO reduced its short-term target for renewable energy to 5% by 2018, down from the 8.2% that it proposed in a draft plan in early March. The final target was announced April 1. The country would like to generate 35% of its electricity from renewable energy by 2024.

CFIUS reported to Congress in February that foreign companies submitted 97 proposed acquisitions of US companies to it for review in 2013.

Roughly half (48) went to an investigation phase. Eight proposed deals were withdrawn. One was resubmitted in 2014 with revised terms.

Twelve of the proposed deals for which foreign buyers sought clearance in 2013 were utility transactions. Of those, 10 involved power generation, transmission or distribution and two were water, sewage or natural gas distribution.

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focused on five key countries — Ethiopia, Ghana, Kenya, Nigeria and Tanzania — to add more than 10,000 megawatts of clean, efficient electric generating capacity. By expanding mini-grid and off-grid solutions and building out power generation, transmission and distribution structures, Power Africa will make electricity access available for 20 million people and commercial entities.

The Millennium Challenge Corporation signed a US$498.2 million compact with the government of Ghana to transform the country's power sector by investing in projects for distribution, energy efficiency and renewable energy. According to MCC CEO Dana Hyde, the compact represents the largest US government transaction to date under the Power Africa initiative.

While the sentiment being generated out of Africa is generally positive, risks remain. Political will is certainly moving in the right direction, but not all dangers have evaporated for investors. Understanding each local market within the context of the broader sub-Saharan African market is key. Often regional factors play a part in local projects and this needs to be fully understood. Attractive returns are possible, but this is often matched by a healthy dose of risk.

Drilling Down: South Africa

Eskom is South Africa's public electric utility and remains the largest producer of power in Africa. It is among the top seven utilities in the world in terms of generating capacity and among the top nine in terms of sales; however, this African giant of electricity generation, transmission and distribution is on the ropes.

Standard & Poor's recently downgraded Eskom's credit to "junk," saying it now regards its management as "weak." In particular, the agency pointed to the recent suspension of chief executive Tshediso Matona — an electricity sector novice who had been in the job only six months — and three other executives to make way for an inquiry. This stands in stark contrast to the accolades Eskom received in 2001, winning the power company of the year award at the *Financial Times* global energy awards in New York.

For a time, South Africa could boast about its ability to produce the cheapest electricity in the world. Its vast coal resources played an important part in this, but inadequate planning and lack of investment, coupled with increased demand that grew steadily from the 1990s, resulted in Eskom having to implement "load shedding" in late 2007 and early 2008. Eskom even went as far as declaring force majeure in January 2008 and required South Africa's gold and platinum mining companies to shut down their operations. Given the significance of the mining industry on the South African economy, its reputation for foreign investment suffered along with GDP growth.

Eskom was able to steady the ship, albeit temporarily. Load shedding was avoided for a time, while Eskom ran its fleet to maximum capacity with little reserve margin, sometimes as low as 1%, and engaged in costly power buy-back arrangements with large industrial consumers in addition to postponing important maintenance.

Today, South Africa is once again experiencing rolling blackouts, as the strain on Eskom's aging fleet and its inability to bring key new builds of Medupi (4,800-megawatt coal fired, comprising 6 x 800-megawatt units), Kusile (4,800-megawatt coal fired, comprising 6 x 800-megawatt units) and Ingula (1,500-megawatt pump storage) on line within the required time frames and within any semblance of the original budgets begin to take a toll.

South Africa is experiencing rolling blackouts. The government is keen to increase private sector generating capacity.

With Eskom being responsible for 95% of the electricity supply in South Africa, the government stated publicly that it is time to increase private sector generation capacity.

The South African Department of Energy has been asserting a role in this, particularly in the development of policy around energy planning. It undertook a comprehensive consultation process that resulted in issuance of an integrated resource plan in 2011 — called "IRP 2010" — as it was effectively completed in 2010.

The IRP 2010 is a long-term national electricity capacity plan that sets out the strategy for establishment of a new generation and transmission capacity for South Africa over the next 20 years, including forecasted requirements in respect of demand-side management and pricing, and the plan includes capacity provided by both Eskom and independent power producers. The IRP is meant to be reviewed every second year to ensure its relevance in view of technological and environmental developments internationally.

The overall result is that a significant allocation of 42% of the new capacity under the IRP will come from renewable energy (solar PV, CSP and wind, totaling 17,800 megawatts), but this is dependent upon assumed learning rates and resultant cost reductions for renewable options.

While this is a significant step toward a greener economy, it should be noted that the total generating capacity planned for 2030 will still have approximately 45.9% allocated to coal, which remains, for now, a cost-effective method of generation given the abundance of the resource in South Africa. Change had to happen though. With 93% of Eskom's electricity being generated from coal-fired stations, there is a consequential environmental footprint. Equally important is the impact on water resources in South Africa, where water scarcity is a critical issue. For this reason, the new Medupi and Kusile power stations will use dry cooling technology.

The renewable independent power program launched by the Department of Energy has made strides toward advancing the targets of government for more private sector involvement in electricity generation. Following multiple bidding rounds, wind and solar IPPs are starting to export power into the national grid.

In the United Nations Environment Program and Bloomberg New Energy Finance, South Africa was called a "runaway star" and one of the top 10 investor countries in renewable energy in 2012. With approximately 3,900 megawatts of capacity from three rounds of competitive bidding by independent power producers, estimates are that over US$10 billion has been invested. This is even more impressive given that it was anticipated the 3,725 megawatts initially sought would be over five bidding rounds. IHS, a consultancy, called South Africa the world's most attractive emerging solar market in 2013.

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The largest number of filings in 2013 was for in-bound US investments from China. The top five countries for which filings were made in 2013 are China (21), Japan (18), Canada (12), United Kingdom (7) and France (7). The top three accounted for more than 50% of all filings.

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.

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 or projects that "involve various aspects of energy production, including extraction, generation, transmission, and distribution" and projects 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, the 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 2013, the committee reviewed 480 proposed */ continued page 19*

Africa

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South Africa is blessed with very good wind and solar resources. According to the South African Department of Minerals and Energy, the average solar radiation varies between 4.5 and 6.5 KWh/m2 (compared to 2.5 KWh/m2 in Europe and 3.6 KWh/m2, at the most, in the US), and annual wind speeds along the coast can translate into 200 W/m2.

The renewable independent power program has sought to procure generation from a range of renewable sources, including photovoltaic, wind, CSP, small hydro, landfill gas, biomass and biogas. There have been four bid submission windows to date as well as a CSP-only bid submission date in March 2014, with a fifth scheduled for August 2015. The 28 preferred bidders from the first bid window reached financial close in November 2012, and most projects are producing power into the grid. The 19 preferred bidders from the second bid submission window reached financial close in May 2013 and the third bid window reached closed in February 2015, with 17 preferred bidders. An additional 3,200 megawatts have been allocated by the Department of Energy and the approach has been successful in introducing IPPs into the South African market.

Falling Tariffs

More importantly, successive rounds of bidding have effectively driven down prices paid to independent power producers. Since round one was launched in 2011, tariff prices have fallen by over 65% for solar PV and over 40% for wind. Certainly the economic downturn in Europe since the renewable independent power program was launched in late 2011 also contributed to ensuring sufficient competition to lower prices. Round one was undersubscribed, but each round since has been heavily oversubscribed.

The total megawatt value of bids submitted in window three amounted to 6,023 megawatts while the available allocation for this window was 1,473 megawatts. In round three, the average price of 74¢/KWh was achieved for wind (down from the average of ZAR 1.14 in window one); 99¢/KWh was the average price achieved for solar PV (down from the average of ZAR 2.75/KWh in window one) and ZAR 1.64/KWh the average price for concentrated solar power (down from the average of ZAR 2.69/KWh in round one).

Round three was also important in that it heralded the large-scale introduction of Enel Green Power into the renewables program. Enel was able to offer very low tariffs for projects by using corporate finance which squeezed out the smaller developers looking at more expensive project finance solutions.

However, speculation is rife that developers have staged somewhat of a comeback in round four with tariff prices that are competitive with those being potentially offered by Enel. It also remains to be seen, given the significant amount of megawatts awarded to Enel in round three, whether the same appetite exists within Enel for so many projects at such low tariffs.

Connection risk remains and, as Eskom becomes increasingly stretched, this risk will be more acute as the rounds progress and a significant number of IPPs look to connect to the national grid. Deep connection works have always been a concern for the program as it matures, and vital strengthening of the network must be implemented.

In addition to the renewable independent power program, the Department of Energy has recently launched a separate baseload independent power program. The policy-adjusted integrated resource plan capacity includes, among other elements, the following proposed new generating capacity in the country in the form of projects approved under the IRP 2010:

- 6,250 megawatts of new coal capacity (14.7% of the total new capacity),
- 3,910 megawatts of new open-cycle gas turbine capacity (9.2% of the total new capacity),
- 2,370 megawatts of new closed-cycle gas turbine capacity (5.6% of the total new capacity),
- 9,600 megawatts of new nuclear power capacity (22.6% of the total new capacity),
- 2,609 megawatts of new hydro power capacity (6.1% of the total new capacity),
- 8,400 megawatts of new wind capacity (19.7% of total new capacity),
- 1,000 megawatts of new concentrated solar power capacity (2.4% of the total new capacity), and
- 8,400 megawatts of new photovoltaic capacity (19.7% of the total new capacity).

Effectively what the most recent determinations from the government mean is that all the megawatts required to be built in South Africa in the medium to long term will be undertaken by independent power producers rather than by Eskom, which has traditionally constructed the majority of baseload capacity in South Africa.

Regional Opportunities

Of importance is that the South African government's determinations also provide for cross-border procurement that can be undertaken for this power, and this is likely to open the way for various possible sources of power beyond South Africa's borders, including hydro power from large projects possibly in Mozambique or the Democratic Republic of Congo and gas projects from the significant gas reserves in Mozambique.

The implications of Eskom's decline affect not only South Africa, but also the entire southern African region. The Southern African Power Pool (SAPP) was created with the primary aim to provide reliable and economic electricity supply to consumers of each of the SAPP members, consistent with the reasonable use of natural resources and the effect on the environment. These members are made up of utilities such as Eskom and its counterparts in the southern African region.

The determinations by the South African government could be a catalyst for development in the entire African sub-region, as the transmission assets necessary to deliver this power expand the transmission capacity in the sub-region, and energy capacity can be added to the megawatts available to intermediary countries to fuel development there. Large-scale power projects will always require a bankable offtaker and, for now, Eskom plays an important role in this.

South Africa, through Eskom, is (or was, prior to the energy crisis in South Africa) Africa's largest net exporter of electricity, sending power to Lesotho, Swaziland, Botswana and Namibia as well as exporting to Mozambique and Zimbabwe.

As the economies forming part of SAPP grow, they are increasingly realizing that they cannot rely too heavily on Eskom and South Africa to guarantee their energy needs going forward, and this is leading to opportunities in the energy space in those jurisdictions. Independent power producers have, for example, grown in the Mozambican market, with Aggreko generating emergency power for sale into the South African grid and Mozambique. Sasol and Gigawatt are also developing independent power projects around the Ressano / continued page 20

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transactions in the five years from 2009 through 2013, or an average of 96 a year. About 11% of proposed transactions were withdrawn during this five-year period, with 3% of withdrawals occurring during the initial review stage and another 8% during the investigation stage.

In 2013, only 8.2% of transactions were withdrawn. Another 11.3% were cleared, but after agreeing to mitigation measures.

ADVANCE PAYMENTS get attention from the IRS.

IRS officials are suggesting that new regulations the agency is expected to release soon on "prepaid forward contracts" may be a complete revision of existing rules rather than an incremental change. They could affect the pattern in which income must be reported under prepaid power purchase agreements. The IRS committed in its current business plan to issue the regulations by summer.

Current IRS rules allow a company that is paid in advance for "goods" that will be delivered in the future to report the prepayment as income over the same period the goods are delivered. However, the company cannot report its book income from the sale any more rapidly than it reports the income for tax purposes, and the prepayment cannot be so large that the company has locked in a profit from the sale.

Some wind and solar companies have signed long-term power purchase agreements with utilities where the utilities pay in advance for a share of the electricity to be delivered over the contract term.

The prepayment is like a loan that the renewable energy companies repay in kind with electricity. The arrangement is beneficial because the utility usually has a lower cost of capital that it can effectively extend to the project in exchange for a discount on the electricity it is purchasing.

MASTER LIMITED PARTNERSHIP rulings resume.

The IRS lifted a hold / continued page 21

Africa

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Garcia region in Mozambique, close to the South African border.

According to a recent report by McKinsey & Company, regional integration would lead directly to capital savings, in addition to savings of between 6% (in southern Africa) and 10% (in east Africa) in the levelized cost of energy. McKinsey & Company predicts that this equates to an annual reduction of nearly $10 billion in the amount the African consumer needs to pay by 2040. These savings translate into a direct reduction in the required tariff an end user would pay if the overall system were to be fully cost-reflective. One downside of regional integration is that the more widely available and cheaper coal and gas-fired capacity ends up being favored over more expensive solar power, resulting in an overall increase in carbon emissions of 4% in 2040. Also, because of differences in load factors, there would be an 11% decrease in all installed capacity while coal and gas-fired capacity would increase or remain the same.

Natural gas is increasing in prominence as an energy source in southern Africa. The significant discoveries of natural gas off the coast of Mozambique in 2012 and the potential for shale gas development in the Karoo Basin, situated under the large expanse of the semi-desert area in the central region of South Africa, has led both private and the South African authorities to focus their attention on natural gas as a key component of South Africa's energy future. The Department of Energy has appointed external consultancies Wood Mackenzie and Mott Macdonald to assist it in the preparation of a gas utilization master plan, or "GUMP," to direct the development of gas infrastructure and the creation of an institutional environment appropriate to the management of South Africa's gas resources in an environmentally-responsible manner over a 30-year period.

The Department of Energy has indicated it intends to explore possibilities for using gas to allow inclusion of more renewable energy in South Africa's generating portfolio. Because gas power can be turned on and off as necessary to stabilize the grid, it is a form of energy conducive to supplementing alternative technologies such as wind and solar.

Unfortunately the market is still waiting for the release of the draft GUMP. The government indicated in April 2014 that a draft would be available in May 2014; however, as of March 2015, nothing had been released.

Sub-Saharan Africa has rich primary-energy resources, with estimates that there are enough coal, gas, geothermal, hydro, solar, and wind resources to deliver more than 12 terawatts of capacity. A very brief snapshot of which resources are most prevalent in certain sub-Saharan African countries shows where the opportunities lie:

- Mozambique – gas and coal,
- South Africa – coal, wind and solar,
- DRC – hydro,
- Tanzania – gas,
- Ethiopia – hydro and geothermal,
- Kenya – geothermal and gas, and
- Sudan – wind.

In addition, Ghana's largest independent power project (350-megawatt gas- and oil-fired) recently achieved financial close, with a South African construction company, Group Five, securing the EPC contract and Rand Merchant Bank (a division of South Africa's third largest bank FirstRand Bank) as coordinating lead arranger for the full commercial debt package, with support from the Export Credit Insurance Corporation of South Africa. The US$900 million project will account for 10% of the total installed capacity and 20% of available thermal generating capacity in Ghana and is expected to help deregulate Ghana's electricity sector.

The next round of bids for renewable energy projects is scheduled for August 2015.

TELPs: A Financing Tool for Municipal Solar

by Jake Seligman, in Washington

TELPs, or tax-exempt lease purchases, may see more use in the US distributed solar market for projects with municipalities.

The structure allows a municipality that wants to own a project, but needs to finance the purchase, to do so without the complication of issuing bonds.

Municipalities have used TELPs in the past to fund construction projects, including energy efficiency upgrades. They can also be used for renewable energy projects.

Solar economics are not as good when a municipality, as opposed to a private party, owns a project. The US government offers a 30% investment tax credit and allows 85% of the project cost to be depreciated on an accelerated basis over five years. However, municipalities do not pay income taxes, and so these benefits go unused in any project that a municipality owns. This has led to use of third-party ownership structures, where a private solar company owns the project and sells electricity to the municipality under a long-term power purchase agreement at a price that reflects a sharing of the tax benefits.

A TELP is essentially an installment sale of a project to a municipality. It is set up in form to look like the sponsor is leasing the project to the municipality, but the municipality has an option to purchase the project at the end of the lease term for a nominal price.

The municipality is essentially buying a construction project, but it pays the purchase price through lease payments over time. In one recent transaction, the municipality paid the equivalent of $2.50 a watt for a commercial-scale solar project.

There may be an operation and maintenance arrangement with the developer during the lease term. Care should be taken in setting the terms of any such arrangement because it could prevent the developer entering into the TELP with the municipality from treating part of each lease payment as tax-free interest on the installment debt. A lender to a municipality can usually treat the interest it receives as tax-exempt interest for federal income tax purposes. However, the debt by the municipality to the developer for the purchase price of the project could be labelled as a "private activity bond," depending on the terms of any O&M agreement, which would make / *continued page 22*

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in March on private letter rulings to companies that want to organize as master limited partnerships.

Master limited partnerships, or MLPs, are partnerships whose units are traded on a stock exchange or secondary market. Partnerships are not subject to federal income taxes; rather, each partner is taxed directly on his share of the partnership's income. Under US tax law, any partnership whose units are publicly traded is taxed like a corporation. An MLP is a partnership that is able to retain its status as a partnership, despite public trading, under a special rule in section 7704 of the US tax code that preserves partnership status as long as at least 90% of the partnership's income each year comes from passive sources — like interest and dividends — or is income from producing, processing, refining, transporting or marketing minerals or natural resources. Wind and sunlight are not considered natural resources because they are inexhaustible.

The IRS put a hold in March 2014 on any further rulings about qualification of entities as MLPs while it sorted out a "hamburger stand" issue. A third of MLP rulings in the year before the hold involved companies that provide services in connection with hydraulic fracturing of oil and gas. The IRS has been concerned about rulings creep as services become farther and farther removed from actual oil or gas production. For example, is owning hamburger stands at fracking sites to feed workers closely enough related to oil and gas production to qualify?

Treasury officials said the IRS is now starting to process ruling requests that it had been holding.

Proposed regulations are expected shortly about what qualifies as income from producing, processing, transporting or marketing "minerals or natural resources."

The hold had affected ruling requests by paper companies to put part of their operations under MLPs to the extent paper companies were asking whether their / *continued page 23*

TELPs

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it harder for the interest to qualify as exempted from income taxes.

Inability to claim the federal tax benefits is still a big hit to the economics.

State policies can help make up part of the gap.

The municipality might qualify for renewable energy credits that can be sold in the market. For example, under the ZREC program in Connecticut, the local utility pays owners of solar projects roughly 5¢ a kilowatt hour for helping reach the state's renewable portfolio standard. Contracts are for 15 years.

Municipalities may also be able to benefit from net metering where excess electricity can be fed into the grid, causing the utility meter to run backwards and reducing the amount the municipality must pay the local utility for the electricity it uses from the grid.

How TELPs Work

In a tax-exempt lease purchase, the developer leases the project to the municipality. Title can reside in either party. The lessor could keep title until all the lease payments have been made. More commonly, the lessee takes title to the system on day one, or at the end of construction, and the lessor retains a security interest to ensure receipt of the lease payments. The lessee has an option to purchase the system at the end of the term for a nominal price.

There are a number of benefits for the municipality as lessee. The obligation to make lease payments is not treated as debt for purposes of state law limits on the amount of debt a municipality may have outstanding. Certain local approvals may not be required that could be required under other financing structures (such as debt). There may be savings from not having to pay a developer to own and operate the project.

Avoiding having the lease characterized as debt for state law limits on municipal debt is usually the main reason for choosing the structure over a straight purchase. The meaning of "debt" in this context varies from one state to the next. Some states view these arrangements as a way for municipalities to avoid public input during the municipal bond process.

A factor in determining whether a lease is subject to municipal debt limitations is whether termination of the lease would result in the municipality giving up more than the unpaid balance of the lease. The term of the lease also should not exceed 120% of the expected useful life of the system.

Non-appropriation provisions also help the lease avoid being characterized as debt for state law purposes. Tax-exempt lease purchases typically include non-appropriation clauses that condition the obligation to pay rent each year on an appropriation from the city or county council. Such clauses are also found in municipal power purchase agreements. If the municipality fails to appropriate, then the developer can terminate the lease and take back the project.

As in power purchase agreements, language can be included to reduce non-appropriation risk to the sponsor. The municipality can be required to use best efforts to appropriate and acknowledge that the electricity from the project is essential to its operations. The municipality can also agree not to purchase power from anyone other than the local utility if it fails to appropriate and the lease is terminated.

By avoiding appropriating funds for more than one year at a time, a municipality can make lease payments out of operating expense dollars rather than capital expense dollars. This allows the municipality to make lease payments the same way it makes utility payments; no additional funds need to be appropriated and no debt needs to be assumed to pay for the project. Municipal debt requires bond issuances, which are more complicated than paying operating expenses, and usually require voter approval.

The municipality is responsible for operating and maintaining the project, but it can contract out for the work.

A TELP is not a "true" lease for federal income tax purposes. The municipality is considered the owner of the project

TELPs may see more use in the US distributed solar market for projects with municipalities.

for federal income tax purposes from inception. As a general rule, the lessee will be considered the owner in any case where the lessee is expected to end up with the assets at the end of the lease term. A nominal purchase option will make the lessee the tax owner from inception.

Municipal leases are usually classified as capital leases for accounting purposes.

They are treated as installment sales for federal income tax purposes. Rental payments are in amounts sufficient to amortize the costs of the project over the term plus interest. The installment paper is considered a debt obligation for federal income tax purposes. The sponsor reports its profit on the transaction over time. It must be careful not to pledge the installment paper as security for a borrowing or the full profit will become taxable upon the making of such a pledge.

With the municipal lease considered debt for tax purposes, the interest component of amounts received by the sponsor under the municipal lease may be exempted from federal, and sometimes state, income tax. However, hiring a private party under a long-term contract to operate and maintain the project could cause loss of the tax exemption on the interest. The interest on municipal debt may become taxable to the lender if there is more than 10% "private business use" of the system. The Internal Revenue Service has rules in Rev. Proc. 97-13 for when a contract with a private operator goes too far. The installment debt would be treated as a "private activity bond." Municipalities are limited in the volume of private activity bonds that may be issued each year, and there are other rules that apply to such bond issues with which the municipality would probably not have complied in order to preserve the tax exemption on the interest element of the rents paid to the sponsor. ◎

US Infrastructure Outlook

The US public-private partnership market continues to diversify, and P3 deal structures continue to mature. A large group of industry participants gathered in New York in mid-March for a breakfast roundtable discussion about US P3s hosted by InfraAmericas and Chadbourne. The following is an edited transcript of the panel discussion.

The panelists are Clare Doherty, director of budget and program analysis for the House */ continued page 24*

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income is from "processing" natural resources. Work on those rulings will now resume.

An internal draft of the proposed regulations is circulating with the IRS and Treasury.

REFUNDABLE STATE TAX CREDITS must be reported as income if they exceed taxes actually paid, even if a company foregoes a refund and carries them forward.

David and Tami Maines qualified for Empire Zone tax credits in New York for opening a new business or expanding an existing one. There are three kinds of Empire Zone credits: an investment tax credit, a wage credit and a property tax credit. The investment and wage credits can be used against income taxes and, once income taxes are reduced to zero, any remaining credits can be carried forward or partly refunded in cash. The property tax credit is limited to the amount of property taxes actually paid in the past.

The Maineses received large "refunds" from the state from 2005 through 2007.

The US Tax Court said the excess investment and wage credits had to be reported as income whether or not they were actually refunded. The fact that the taxpayer had the option to take them in cash meant the refunds were "constructively received."

However, since the property tax credit can be used only to get a refund of property taxes that were actually paid earlier, it merely reduces real taxes. If the taxpayer benefited from deducting the taxes earlier, then it must report the refund as income. If not, then the refund is not income. This is called the "tax benefit rule." If an earlier tax benefit, like a deduction, was claimed and the basis for it is now disappearing (since the taxes paid are being given back), then income must be reported to reverse the earlier benefit.

The case is David J. Maines v. Commissioner. *The Tax Court released its decision on March 11. The court reached a similar conclusion in another case six days later called* Yigal Elbaz v. Commissioner.

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Transportation and Infrastructure Committee, José Antonio Labarra, general director of transport concessions at Isolux Infrastructure, David Livingstone, managing director at Citigroup, Zoe Markwick, commercial director at Skanska Infrastructure Development, Mike Parker, US infrastructure advisory leader at Ernst & Young, and Nick Phillips, assistant vice president at John Laing. The moderator is Doug Fried, a partner from the Chadbourne New York office.

Current US P3 Market

MR. FRIED: Zoe Markwick, what would you say were the biggest surprises in the market over the last 12 to 18 months, both positive and negative?

The European P3 market is dormant, so the big players are moving back into the US market.

MS. MARKWICK: Here is my list of surprises, and you can tell me if you think they are positive. My number one surprise of last year was Joe Biden's comment that landing at LaGuardia Airport — which is procuring a P3 for its central terminal building — is like landing in a third-world country. Thanks, Joe Biden. Another surprise on my list was a Democrat lost the election for governor in Maryland, which led to a light rail project called the Purple Line P3 being put on hold. Maryland's new governor — Larry Hogan, a Republican — said during his campaign that he would stop the Purple Line. Thank you for that surprise.

Another surprise, which I am very happy to see, is bank market pricing and bank appetite are getting more aggressive. I love the rush to the bottom. Lastly, the size of public contributions in P3 projects is on my list of surprises for the last 12 to 18 months. Public authorities are putting their hands into their deep pockets and coming up with a lot of money for P3s, in some cases as much as a billion dollars, which creates some interesting structures for some of the projects.

MR. LIVINGSTONE: IFM's winning bid of $5.725 billion to purchase the Indiana Toll Road out of bankruptcy was a big surprise for me. You could be flippant and say, "That's good; we will have another restructuring in another five years." However, it shows that there is a tremendous appetite for brownfield toll roads, and there just are not many of them in the United States. It is hard to come up with a metric that justifies a number that large.

MR. FRIED: José Antonio Labarra, the I-69 Section 5 project was Indiana's second major P3 to reach financial close in as many years. What can the market learn from this project and from Indiana's successes?

MR. LABARRA: The first thing to learn is that the Indiana Finance Authority or IFA ran a well-managed procurement, and all the deadlines and targets were met. Sticking to a schedule helps avoid increases in bidding costs and keeps bidders interested in the procurement, not other projects.

The second thing is that IFA did the East End Crossing a year before the I-69 Section 5 project. Most of the complicated and tough issues, such as the appropriations risk for the availability payments, were already analyzed and resolved, and the market had already gotten comfortable with the East End Crossing transaction which it made it easier for IFA to go to the market with the I-69 Section 5 project.

Sources of Revenue

MR. FRIED: Mike Parker, do you have some thoughts on availability payments?

MR. PARKER: I know you will ask me about reauthorization of the federal highway and transit funding programs, and I think the two are connected. We met with the CFO of a public transportation agency recently and talked about how assuming a 2% growth rate in federal funding for the next 30 years is aggressive. I think historically that would have been a baseline assumption that you could have made from a planning standpoint. However, we have had to live for quite a while now with continuing resolutions (which are appropriations bills that continue pre-existing appropriations at the same levels as the previous fiscal year) without new funding bills. The federal share in transportation funding has been declining in the US. Assuming no growth is a more prudent assumption for this particular public transportation agency.

We are seeing some states take action on the gas tax, but until we see a situation where you have revenue streams that are at least rising at the pace of the operating costs of these public agencies, their ability to lever, whether it is through availability payments, GARVEEs or a normal debt program, will be increasingly limited. That puts pressure on the federal government to come up with more money through reauthorization of its transportation programs, unless other local revenue streams can be found.

We are seeing other types of procuring agencies coming to market looking to do other projects besides highways, and they are doing this with availability payments. The US is a big country, with lots of local communities, so there is a little more moving now. However, there are some revenue constraints in the current funding environment for projects over $500 million or even $250 million.

MR. FRIED: Does that leave more room for demand-based, revenue-risk deals?

MR. PARKER: If the projects are economical, then yes, but a lot of the easy pickings have been done. There are many questions today around managed lanes. It will be very important to see over the next few years how some of the managed lanes projects perform that are ramping up now. There is a huge appetite among public agencies for managed lanes, but there is also concern that these projects do not always pay for themselves. If they end up paying for themselves, then more such projects will follow.

Reauthorization

MR. FRIED: Clare Doherty, what do you think about reauthorization? Will it happen before the deadline? We have been to this movie before, haven't we?

MS. DOHERTY: Yes, we have done this before. The House is working internally with all the committees that need to make reauthorization happen. We are also reaching out to the Obama administration, working with Treasury, and talking to the US Department of Transportation, and the Senate is working as well. Deadlines really help force action in Congress and help force people to come together. Everyone knows about the May 31, 2015 deadline for reauthorization of the federal highway and transit programs. Lots of states are getting / *continued page 27*

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A TAX EQUITY INVESTOR who made capital contributions to a partnership in exchange for being allocated state tax credits bought the tax credits, and the sponsor had to report the capital contributions as income, the US Tax Court said.

The capital contributions were 53¢ per dollar of tax credit. The court reached the same conclusion in another case last year.

An individual bought a 674.5-acre farm in Albemarle County, Virginia, 10 miles south of Charlottesville, in 2001. In 2005, he promised a local public interest group that the land would remain undeveloped by giving the group a "conservation easement" over the property.

Virginia allowed a tax credit for 50% of the fair market value of any such easement. However, no taxpayer could claim more than $100,000 in credits in the year the easement was donated, and then another $100,000 in each of the next five years for $600,000 in total. Any unused credits could be sold or transferred to another taxpayer. A market developed in them over time.

One had to file a form and an appraisal with a state agency, which would then issue an acknowledgement letter and an "LP number" identifying the tax credits. The letter had to be attached to tax returns. The LP number had to be used for any transfer.

The taxpayer did a deal with the Virginia Conservation Tax Credit Fund LLLP in late 2005. The fund planned to contribute 53¢ per dollar of tax credit expected to a partnership. (The individual landowner owned the farm through a corporation. The farm was in a disregarded subsidiary of the corporation. When the fund made the capital contributions for the tax credits, they turned the disregarded subsidiary into a partnership.)

The fund made capital contributions for 53¢ per dollar of projected tax credits to the partnership. The partnership allocated the fund 1% of income and distributed it 1% of cash, but otherwise allowed it all the tax credits less $300,000 that were reserved for the sponsor. The sponsor guaranteed the fund that / *continued page 27*

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ready to ramp up their construction seasons, so they have been aggressive about visiting Congress. We get a lot of visits from mayors and governors, and these visits will continue. We are optimistic. We are driving to meet the deadline.

MR. FRIED: What happens if we miss the deadline?

MS. DOHERTY: That is a challenge given the status of the highway trust fund right now. I think it will all come together in the summer. Around May, there will be a lot of pressure as states will be talking about the projects they will have to delay if reauthorization does not happen. We are already hearing this from a lot of states. States need certainty that funds are coming before they move forward with projects. I also think members of Congress, especially the Republicans who came in this year, really want to show that they can get an infrastructure bill done. Transportation Secretary Foxx has come to see us a lot, and he has a great rapport, as a former mayor, with a lot of our members. We are optimistic that will help.

All of that said, if you have followed Congress over the last few weeks, you know we have had a few rough patches.

MR. PARKER: If there is no reauthorization of the federal transportation programs, or reauthorization does not happen by the deadline, it does not mean there will be a shutdown of the federal transportation programs. In the past, Congress has used continuing resolutions to allow programs like TIFIA to keep rolling along at the current funding levels, which are robust. It would be different if there were not even a continuing resolution to continue pre-existing appropriations at the same levels.

MS. DOHERTY: Right. Without getting too much into the weeds, no reauthorization is not the same as the highway trust fund running out of money, which is projected to happen in the summer.

Interest in US P3 Market

MR. FRIED: Nick Phillips, global developers and investors are continuing to pursue projects and set up offices in the US. What do you think is driving these firms, and will this trend continue?

MR. PHILLIPS: Our company is one of these investors. I do not think the trend will change. If you look around the world, there is very little pipeline in the P3 market for a lot of these companies. Europe is dormant, which is a nice way of putting it, and a lot of the players in the industry have been in the US before and have now come back. From a John Laing perspective, we were here in 2007 and 2008 and decided that the market was not ready yet, so we went to Australia and focused a lot of resources on that region.

The US is the large market. It is a country of more than 300 million people. It is relatively wealthy, at least at the personal income level. At some point, I think everybody in this room believes that the US P3 market will really take off. That's why we are all here. You also do not want to be the one left trying to break into the market when everybody else already has credentials. If you look at qualifications processes now, little weight is given by procuring agencies for projects that companies have done in foreign countries. Procuring agencies want local experience.

The bid for the Indiana Toll Road showed that there is a huge appetite for American infrastructure. I do not see that changing. I also do not see where else these companies could go at this point, unless you want to get aggressive and go to the Middle East or Africa or South America.

MR. FRIED: Zoe Markwick, what impact do you think global economics and political trends have on the US P3 market?

MS. MARKWICK: Like Nick said, there's not a lot to do elsewhere. The P3 market participants are in the US because many of the overseas developers are not seeing their normal deals back home.

The increasingly positive outlook in the US is very helpful. We continue to see private capital looking for a good home. It regards infrastructure as a positive investment. From our company's perspective, the US is now our largest single market and our biggest growth market. While people might regard us as foreigners, we are a domestic contractor now.

Sources of Financing

MR. FRIED: David Livingstone, what do you think the likelihood is that we will continue to see bank financing mixed in with private activity bonds, TIFIA and other sources of debt?

MR. LIVINGSTONE: The reason why bank financing was more attractive for the I-4 Ultimate project that closed last summer is the extremely long construction period, and a relatively short amortization period. Banks could deal with the negative carry a lot better than the bond market where all the money must be drawn upfront.

If you have a construction period of three years and less and are looking for a longer tenor of debt in the range of 25 to 30 years, then the tax-exempt bond market will be the most attractive financing for P3s. We have tried to find ways to link bank and bond solutions, but inter-creditor issues have been an impediment.

MR. PARKER: People are starting to pay a little bit more attention to the private placement market. There are questions whether this is something that could be enabled during the initial rounds of bidding and how a private placement would work within the context of a bid process. However, going taxable and going long is an interesting possibility today, and some of the benefits in terms of future flexibility and refinancing, when compared with how aggressive the financing solutions can be, and the ability to avoid the negative carry, are pretty interesting.

Political Risk

MR. FRIED: Mike Parker, Project Neon in Nevada was cancelled after three teams were shortlisted. The Illiana procurement in Illinois was put on hold and the Purple Line P3 in Maryland has been delayed. What can be done to address this risk?

MR. PARKER: There is no silver bullet.

First, big projects are controversial by their nature. Large infrastructure projects can generate significant levels of opposition that have nothing to do with the fact that they are P3s, especially if there are environmental considerations that create opposition. There is also risk where the projects have significant costs and are competing with other projects for funding. Sometimes, the problem is the physical dimensions of a project, and sometimes in a cash-strapped state there are questions about budget priorities.

Having political champions matters. Some of these states that cancelled or delayed projects were changing governors at the time.

MS. DOHERTY: I would add that this issue was discussed in the special P3 panel that Congress convened last year, and it was a controversial subject. Ranking members feel that there has to be a lot of transparency around the deals so you get buy-in at the community level. You need stakeholder meetings and community outreach.

I think there is a lot of support for laying the numbers out, talking about the alternatives, talking about the options and sharing the value-for-money analyses. We have members of Congress who wanted to read all of the value-for-money analyses — and they did. They questioned people at hearings about their rates of return.

Those numbers should be on the table, but they are not */ continued page 28*

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it would receive $3,050,000 in tax credits and agreed to indemnify the fund for any loss or disallowance of the projected credits. In fact, the tax credits turned out to be more after an appraisal delivered in late 2005 suggested the easement was worth more than expected.

The parties allocated the extra tax credits to the fund without bothering to amend the partnership agreement. The fund increased its capital contribution from $1,616,500 to $1,802,000 to account for the extra tax credits.

The capital contributions were put in an escrow account held by a lawyer hired to implement the deal. The money was not released from escrow to the sponsor until mid-2006 as the fund did not authorize the release until then. The state did not issue a letter confirming the tax credits and assigning an LP number until March 2006. The lawyer did not file the paperwork until 2006.

Meanwhile, 35 individual investors purchased from the fund tax credits of $2,420,000 that they claimed on their 2005 returns.

The sponsor had an option to buy back the fund's 1% interest for fair market value starting in 2010.

The IRS treated the transaction as a disguised sale of tax credits by the sponsor and said the $1,802,000 in capital contributions by the fund should have been reported as income by the sponsor in 2005.

The US Tax Court agreed.

A disguised sale occurs where one partner contributes property to a partnership and the other contributes cash, and then the cash is distributed to the partner who put in the property. There is a presumption that the two events are linked if the distribution to the partner contributing the property occurs within two years.

The sponsor argued that there was no sale of tax credits; rather the partnership simply allocated the fund an agreed share of tax credits in the fund's capacity as a partner.

The court said no. It saw money going into the partnership and then going out within two years to another partner */ continued page 29*

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always, so I think that transparency and public support could make a difference.

Congressional Report

MR. FRIED: Clare Doherty, the House Transportation and Infrastructure Committee recently completed a major report on P3s. Could you share with us the major conclusions?

MS. DOHERTY: Back in September 2014, we announced a bipartisan report on P3s. The special panel was in existence for a period of six months. We had 11 members, including six Republicans and five Democrats. We did seven roundtables and two hearings, and we came to New York and even went to LaGuardia with the members to learn about the airport P3.

We heard a lot about TIFIA. Probably the number one thing that people told us was to continue TIFIA because it is critical to the P3 market. We heard a lot about strengthening the public sector's capacity to do the best deal possible and the need to take time to educate the stakeholders. One of the recommendations was to establish a procurement office at the US Department of Transportation to be a resource center to help states and project sponsors.

The resource center could help states look at existing deal models. One of the things I think members were surprised to learn was that states have not necessarily been meeting and sharing information about their experiences with P3s. If some states are developing best practices and have good successes and are doing something right, we should be sharing that information and helping other states.

We really wanted to look also at encouraging some simplification in P3 contract provisions. We heard from public officials who said it took a year to learn all the terms of the deal and from others who said they signed contracts with terms they did not actually understand.

The other thing is there are various federal programs for P3s that are just getting off the ground. One that we just put in the last water infrastructure bill is the new WIFIA program. We have been big proponents of encouraging the Army Corps and US Environmental Protection Agency to work with the US Department of Transportation and Treasury to look at best practices for P3s to apply to their programs.

MR. FRIED: Can transportation truly be a bipartisan issue?

MS. DOHERTY: Definitely. Members are excited about infrastructure. It is one issue that brings them together. They also like to see, tangibly, what they will get for their investment and how quickly a facility will open. One of the challenges with innovative financing is explaining to members when that project might actually come to fruition.

Our panel had standing-room-only events for most of our hearings. People want to know when Congress will deliver more infrastructure. We talked about water, airports, public buildings, waterways, highways and transit. We heard from Canadians and a number of Europeans. Members are curious as to why project delivery is done differently in other countries.

We could mix all the members up and they would all have very different issues and maybe their reactions would depend on whether their states have actually done P3s. Their reactions also might vary depending on whether a member comes from a region in which tolling or other financing approaches have been used or from certain states that will never do P3s and that do not go to the debt markets.

Most activity remains in highways, but interest in social infrastructure is increasing.

Active States and Sectors

MR. FRIED: Which states present the most opportunities going forward?

MS. DOHERTY: We have looked at the states that have been active in the TIFIA program. TIFIA creates a lot of tension among members because they see some states that have availed themselves of the opportunities and are taking federal aid dollars and leveraging them to create projects, and there are other states that still work on a pay-as-you-go basis.

Many of you know about the rural set-aside and other things Congress has attempted to put into legislation to encourage rural America to consider innovative financing strategies, but a limited pool of states are currently interested.

MR. PARKER: Clearly Florida is active. California has a question mark, whether at a state or local level, but it is a massive market, bigger than most countries. Likewise Texas, especially if you look at both the state and local level and across different categories of infrastructure. The New York City region, whether or not specifically the City, or different agencies that have different legal authorities, could be active. We are seeing activity with the Port Authority, where LaGuardia is one step, but certainly building on the Goethals bridge project. There is broad interest in the New York City region and a huge need.

There is probably a broader interest in Georgia after the governor was reelected. Georgia has a great design-build-finance project that is in procurement now, but I think if you look more broadly at the student housing market or things like that, depending on how you define the deal flow, there may be opportunities there.

One thing to consider is that we have become very narrow and focused on transportation and highway P3s. We are seeing some sponsors get more creative by looking outside that sector. Depending on your perspective, whether you are a vertically-integrated contractor or a fund or a certain type of lender, there will be differences in where the deals are going to be for you.

MR. PHILLIPS: I agree with Mike Parker that there is often a focus on transportation and everything else is kind of falling by the wayside. In the introduction to the panel, we mentioned the deals that closed last year, and they were all highway projects.

We have seen development in other sectors, but it has not been through a traditional procurement process. The Carlsbad desalination plant took time, but hopefully is an example that Texas, Florida and other states interested in water can use. We have seen a lot about student housing and waste water, so there is significant potential deal flow that comes from outside interstates and highways. That is probably an area on which we need to start spending more resources and discussing more as part of the industry as opposed to just having this very highway-focused view.

MS. MARKWICK: It is hard enough to do a highway P3 with a state department of transportation that has done highway P3s before. Good luck with a municipal water authority.

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who contributed property. It said a number of factors made this transaction essentially a sale of tax credits.

They included that there would have been no transfer of cash but for the amount of tax credits delivered. The fund had no entrepreneurial risk; the amount of tax credits was known at the start. The amount was guaranteed by the sponsor. The fund could get its money back to the extent the amount of tax credits fell short. The share of tax credits to the fund was disproportionately large in relation to the fund's interest in partnership profits.

The court said the "economic benefit theory" required the sponsor to report the income in 2005, despite not being paid the cash until 2006. A taxpayer must recognize income in the year in which any economic or financial benefit is conferred. The sponsor benefited in 2005 because the cash was irrevocably set aside in escrow for the sponsor that year and was beyond the reach of the fund's creditors. Substantial restrictions on release of the money would have prevented the income from having to be reported in 2005, but in this case, only ministerial tasks remained before distribution.

The case is SWF Real Estate LLC v. Commissioner. *The Tax Court released its decision in early April. Courts have treated other partnership transactions as sales of state tax credits in at least two other cases. (For earlier coverage, see the June 2011* NewsWire *starting on page 29 and the April 2014* NewsWire *starting on page 21.)*

LIABILITIES ASSUMED BY A PURCHASER of three nuclear power plants to decommission the plants cannot be added to the cost basis in the plants, a US appeals court confirmed.

Exelon bought three nuclear plants in 1999 and 2000 for $93.3 million in cash and the assumption of $1.687 billion in decommissioning liabilities. In addition to the plants, it also received funds that had been set aside for decommissioning. Normally, when / continued page 31

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MR. PHILLIPS: Let's hope that some projects get done and can be used as a template while the industry develops.

MS. MARKWICK: You need to consider the deal size compared to the effort. We are a construction company and we care about construction revenues. A $2.5 billion highway in Florida is not the same as a $200 million social project led by a municipality.

MR. PARKER: There will not be many projects in the university space, for example, that are over $500 million, let alone over $200 million, when you look at them building by building.

MS. MARKWICK: Social projects in the UK and Canadian markets have repeatability. You can do a lot of schools and hospitals in Canada. You cannot crank out lots of them in the US because each state has different rules and it is not just each state; each municipality has a different set of risks, issues and documents.

The $3 to $5 million of external costs and the opportunity cost that you must spend bidding on one project is not an investment in a potential pipeline of similar projects.

Private Activity Bonds

MR. FRIED: David Livingstone, how important is the PABs market in today's P3 deals? Is there enough PABs authority for the P3 deals currently in the pipeline? As of January 2015, almost $12 billion of the $15 billion available through the US Department of Transportation PABs program was already allocated.

It is harder to find repeatable projects in the US, where each state has its own rules, than in places like the UK and Canada.

MR. LIVINGSTONE: PABs have certainly become an important financing component for P3s. Other than the I-4 Ultimate project, virtually all other greenfield transportation projects have been done with PABs over the last few years. The day of reckoning is not here just yet.

You are correct that the US Department of Transportation website gives the impression that there is only $3 billion in bond authority left. But if you look more closely, $600 million has been allocated for the Knik Arm Bridge in Alaska that will not be used. Also, $1.2 billion was allocated for the Pennsylvania Bridges P3, which will not all be used. How much is going to be used for I-77 in North Carolina, SH 288 in Texas or Portsmouth Bypass in Ohio? You probably have $5 billion left to allocate, and only about $5 billion in bonds have actually been issued at this point.

Private activity bonds are an important tool. While I do not think we are in a crisis situation this year, and maybe not even next year, we will be there soon.

MR. FRIED: The Obama administration's proposal for a "qualified private infrastructure bond" program — called QPIBs — would broaden the categories of public-private infrastructure that can benefit from tax-exempt bonds, eliminate volume caps, and do other things. Do you think this program will pass Congress?

MS. DOHERTY: It will have to go through the Ways and Means Committee, which is the tax-writing committee. These types of proposals create heartache because you have to figure out how to pay for them. There is a cost to the government of allowing more tax-exempt debt.

Going back to the question about the PABs volume cap, we are looking at it. We get many state and local visitors who want financing tools like this. In our special P3 panel, we heard a lot about flexibility to use PABs for water and public buildings and other types of infrastructure.

MR. PARKER: It is not my place to speculate whether the program will pass, but there does seem to be a serious conversation around it, and the idea has come up in the context of WIFIA as well.

Note that while the program would expand the categories of infrastructure that could benefit from tax-exempt debt, my understanding is that public buildings ultimately were not included in the proposal. Anecdotally, my understanding is that there were some concerns around whether or not including them would create some loopholes that the real estate industry could exploit more widely than expected.

The program would be a welcome development if it passes Congress. If you look at other countries, there are huge debates around value-for-money analysis, and these countries do not have tax-exempt debt. Here we have tax-exempt debt and, when you try to make tortured arguments about value for money when the scales are already tilted a little bit, it can be uncomfortable. The program would help balance the scales.

Is TIFIA Essential?

MR. FRIED: Zoe Markwick, is TIFIA essential to grow the US P3 market?

MS. MARKWICK: Arguably, no. I think it depends what kind of projects you are talking about. With the I-4 Ultimate P3, for example, there is a school of thought that a AAA-rated state like Florida that is putting $1 billion of its own money into the project does not need $1 billion from TIFIA. This is a cost-driven analysis from the perspective of the Florida Department of Transportation.

MR. LIVINGSTONE: I absolutely agree with you on availability-based deals. It is a cost-of-capital thing. If TIFIA is not there, PABs and bank markets are there. However, on revenue-risk deals, which is what TIFIA was originally set up for, TIFIA is essential. You would not have gotten the Texas managed lanes deals done, without tremendous amounts of additional state subsidy, without TIFIA.

MR. FRIED: So should TIFIA even be used for availability-based deals?

MR. PARKER: Yes. The challenge that we face is that everybody wants to talk about how P3s look when we do a value-for-money analysis on a side-by-side basis with public debt. TIFIA is the juice that makes the availability-payment P3s competitive, especially when we do not have fully tax-exempt private activity bonds on the other side. TIFIA helps make the numbers work when we do not have the performance history to bolster every argument about the value of risk sharing or efficiency gains that we might get with a P3.

With TIFIA, you can say to a government that is considering doing a P3, "Look, you can effect this risk transfer that you want and not pay any extra in the cost of capital because you have TIFIA." Remove TIFIA and the numbers will not look as pretty unless the bond market tightens substantially.

MS. MARKWICK: I want to respond to that. It is a fundamental of our world that you align risk and reward, right? I get that the departments of transportation want cheap money. Right now, though, the departments of transportation are taking the benefits of TIFIA in lower costs, and the bidders take the risks of having to be the borrower with a lender / *continued page 32*

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someone buys assets and also assumes liabilities to which the assets are subject, the liabilities are included in asset basis and can be recovered through depreciation or amortization. An example is where a power plant is purchased subject to outstanding project-level debt to a bank syndicate.

Various accountants and lawyers whom Exelon consulted warned that the IRS would probably not allow the decommissioning cost to be included in basis. Exelon tried to get a private letter ruling from the IRS, but was told the IRS does not believe the liabilities can be put in basis. The company took the position anyway on its tax return.

It lost in the Court of Federal Claims in October 2013. The court said there is no dispute that assumed liabilities go into cost basis, but the issue is when. It said the obligation to pay the decommissioning costs must not only have "accrued," meaning that there must be a legal obligation to pay and the amount can be determined with reasonable accuracy, but there must also be "economic performance" before it can be added to basis. The court said decommissioning is a service. There is no economic performance of services until they are actually performed.

Exelon complained to a US appeals court that it should not have to show "economic performance" when calculating basis in purchased assets. The court said in March that basic accrual concepts, including economic performance, apply even in situations when someone is purchasing an asset to decide whether liabilities assumed can be put in asset basis.

The case is AmerGen Energy Company, LLC v. United States. *Special rules in the US tax code allow utilities to deduct — not add to basis — amounts set aside for decommissioning when they are deposited in qualified decommissioning funds.*

TRANSFEREE LIABILITY can make the selling shareholders of a company liable for taxes the company should have paid, / *continued page 33*

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with whom they cannot interface.

From a borrower's perspective, I would rather bring my relationship banks to the table with me than TIFIA. If I will be at the table with TIFIA on $1 billion loan, especially with the long time it takes on a project like I-4, then I want to be able to compare my TIFIA financing and my bank financing.

If you look at the difference between what people bid on committed financing, between the TIFIA term sheet and the package of diligence and documentation that is put together on the bank financing, the difference between these two is a really clear indicator of the lack of comfort the bidders have with the TIFIA process. We would never in good conscience go to investment committee and say, "I have this 20-page term sheet, and I can understand approximately half of what it means, but it will be fine."

The $3 to $5 million in cost to bid on one project may not be an investment in a pipeline of similar projects.

MR. FRIED: It seems the states are getting the benefit of lower cost capital and they are getting the benefit of all the risk transfer going to the private sector. They are getting their cake and eating it, too.

MR. PARKER: I am not disagreeing with the general principle. However, if there is no possibility of a TIFIA loan, at least in the past few years, and maybe the markets are tightening, it would be a lot harder to make the argument for a P3. When you can point to a loan with an interest rate below 3%, a lot of those CFO objections around "how come we are not doing our own tax-exempt debt?" start to go away.

MR. FRIED: What about the cost overruns that states and cities have on their publicly-financed projects when they do not have a fixed price?

MR. PARKER: When you are comparing design-build to design-build-finance-operate-maintain, it is a harder argument to make at the front end for these savings. Our engineering colleagues are the ones who have to give us those numbers and make that case.

MS. DOHERTY: The benefits of P3s that members of Congress hear are the project is on time and on budget, there are maintenance warranties and the roads are going to last. You will not have to replace the project in five to 10 years. One issue on which we have spent a lot of time is bridges. State governors will not repair or replace them and then the cost to do so increases over time to a point where it becomes enormous. Eventually, they come to Congress and ask us to fund the work.

On the P3 side, members love the benefits, but when a private company is earning a high rate of return and will put a toll on use of what was formerly a public asset and my constituents have to pay that, it creates some tension. We heard a lot of case studies of states that have not had good track records with delivering public facilities efficiently and spending tax dollars wisely. That is the counterbalancing point for a lot of people.

MR. PARKER: Don't get me wrong. Tax-exempt bonds are a good idea. We would much prefer to see the market in a situation where the market can control the project and control the price and can bring a bid.

Toll-based concessions are challenging if you want to run a procurement process and TIFIA will not engage with the bidders and the bids may be based on fundamentally-different assumptions. In an availability-based deal, there is at least the possibility of a common term sheet. The idea of creating bond solutions that equalize the cost of capital are great.

MS. MARKWICK: We have people in the room here who have helped run TIFIA. Can I ask why TIFIA runs the process the way it does?

MR. FALK: Jake Falk from Chadbourne. I was director of the office of infrastructure finance and innovation at the US Department of Transportation.

The answer goes back to the evolution of TIFIA. When TIFIA started in 1998, it was looking for deals and they were hard to find. When a deal did come in, there was a lot of focus on how to pull together that deal, and there was an expectation that it would take a long time. The early deals were often the riskier and more difficult projects that had no other access to capital markets.

Over the years, TIFIA became a much more competitive program. It got a lot of new funding from Congress in 2012. All of a sudden, TIFIA had to ramp up and significantly change its process to execute deals more quickly for projects that were, in many cases, closer to being shovel ready. If you look at TIFIA over the course of that full evolution — and I don't know that everybody in the room will agree with this — it has actually done a pretty remarkable job getting to where it is today.

Also note that P3s are only one of the types of projects that come into TIFIA. The TIFIA office also sees a large number of publicly-financed projects that, in many cases, are the ones that are moving more quickly. P3s have an additional challenge in accessing TIFIA in that you have a bidding process before the ultimate borrower can get to the table.

TIFIA is trying to move more quickly and professionally. It is happening with some of the publicly-financed projects. The TIFIA office is trying to get the same traction with P3s, but it is taking time.

Growing the P3 Pipeline

MR. FRIED: What else do you think the federal government can do to help state and local governments grow the pipeline of P3 projects?

MS. DOHERTY: We have seen varying capacity among states to bring P3 projects to the marketplace and also to meet the TIFIA deadlines. We see mixed abilities to put together a real finished project that is really ready to go to financial close.

A procurement office to help project sponsors could be helpful. The administration last summer held a White House forum on P3s and it has set up a new office at the US Department of Transportation to be a resource center to help state and local officials.

People recognize across the federal government that they have to help public officials by equipping them with the tools they need. Putting a P3 tool kit and other things on a federal website is helpful, but I think some people need more hand holding or advice and consultation.

We are looking to raise the bar for states / *continued page 34*

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but that the new owners failed to have it pay.

Four individuals owned a regular "C" corporation called Little Salt Development Co. whose sole asset was 160 acres of land near Lincoln, Nebraska that was used for farming and duck hunting. The corporation sold the land to the city for $472,000 in June 2003, receiving $471,111 after subtracting settlement costs. The corporation had a taxable gain on the land of $432,148.

MidCoast Investments approached the shareholders with an offer to buy the company for $358,826, or the cash in the company, less 64.92% of the tax liability on the capital gain, and said it would cause the company to file a return to pay the taxes owed on the land sale.

The transaction closed in August 2003.

The shareholders figured they were better off by $58,842 by taking the offer compared to keeping the proceeds that would have remained from the land sale after paying taxes.

MidCoast failed to have the company pay the taxes it owed. The IRS assessed back taxes against the company and, when it was unable to collect, went after the former shareholders.

Section 6901 of the US tax code authorizes the IRS to pursue any remedies it has under state law to collect taxes where property is transferred fraudulently to avoid creditors. Nebraska has adopted the Uniform Fraudulent Transfer Act. That statute treats a transfer as fraudulent as to present creditors whose claims arose before the transfer if reasonably equivalent value is not received in exchange and the debtor was insolvent at the time or became insolvent as a result of the transfer.

All the elements of a fraudulent transfer were present in this case. The IRS had a claim against Little Salt Development Co. for taxes before MidCoast bought the company. Little Salt received no value. It had an estimated tax liability at the time of $167,737. The transaction left it insolvent because MidCoast immediately stripped all the cash out the company by purporting to borrow it in exchange for an uncollectable note that it left in the company.

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to be able to sit at the table by themselves and think through what happens when their projects run into challenges. We talk a lot about where does the procurement office sit and can this office be internalized and staffed by career officials that are not associated with the governor or the mayor. Canada shared with us that one of its best practices has been institutionalizing its programs with career officials.

MR. FRIED: José Antonio Labarra, how could the federal government make a difference?

MR. LABARRA: One way the federal government can help is through education, which includes educating the politicians, educating the different state departments of transportation, and educating the stakeholders. I mean "educating" in the most ample meaning of that word.

Another thing the federal government can do is help with planning and reducing the amount of time it takes to get through the project delivery process and environmental approvals. Some projects start procurement even before having the record of decision which creates risk. The federal government has to streamline the process and maybe improve it by facilitating a more certain timeline.

We mentioned contract standardization. Contract guidelines and similar efforts will help, but education and the planning process are for me very important objectives for the federal government.

MR. FRIED: Nick Phillips, would the growth of P3s in other sectors, such as social infrastructure, happen more quickly if these projects had access to government financing programs like PABs and TIFIA?

MR. PHILLIPS: We should ask Clare Doherty. We know WIFIA has been approved, but my understanding is the program has not been funded. Will we see WIFIA in practice at any point in the next few years?

MS. DOHERTY: We authorized it, but the appropriators have actually to fund it. We heard the Environmental Protection Agency may be ready to issue guidance and we are working with the Army Corps.

MR. PHILLIPS: I think advancing projects in these sectors has much to do with sources of funding. We are not talking about revenue-risk projects in these social sectors. They are availability-based deals.

Something similar to TIFIA is probably unnecessary. It takes time to understand these types of assets and to structure the deals properly. We are seeing some movement in justice consolidation facilities. It would be good for the federal government to get involved as some of these court houses are federal. There has been discussion around a potential project in Fort Lauderdale, but it is not at the top of the federal government's priority list. Maybe the US General Services Administration can help to move up the timeline.

We were talking earlier about TIFIA. Where TIFIA really comes up is in the road sector where operating costs maybe are lower. If you start getting into public buildings, transit, water or some other areas and more complex facilities where there are big warranty issues, the discussions around P3s are different. There is a fairly clear understanding about what operating costs will look like for a highway project in a conventional area, particularly for a part of the highway system where maintenance has been scaled by state departments of transportation. It is very different when we start getting into some of these other sectors. ◎

New Economics for Renewable Energy in Poland

by Igor Muszynski, in Warsaw

A new renewable energy law will transform the market in Poland by changing the support scheme for renewable energy projects.

The Polish parliament adopted the new law after more than three years of debate. The new support rules will not take effect until January 1, 2016, but renewable energy companies developing projects in Poland must soon take certain steps to prepare for this date.

Auctions

Renewable power in Poland will be supported under a new scheme of revenue guarantees starting January 1.

The guarantees will be provided by a newly-created state-owned entity called the Renewable Energy Settlement Operator (Polish abbreviation "OREO") for a period no longer than 15 years from the date of the first delivery of power to the grid from a qualifying project.

OREO will be financed by a special fee added to every electricity bill issued to the final customer. The right to receive a guarantee will be granted in auctions, which will be carried out by the Energy Regulatory Authority. The Polish government will define, by the end of October each year, the number of megawatt hours to be covered by the guarantees to be issued in the upcoming auctions and the total value. The Minister of Economy will set the maximum price to be offered in the bids, called the reference prices, for each renewable power technology eligible for bidding, at least 60 days before the auction. The reference prices for the 2016 auction will be announced by May 31, 2015. This procedure will be repeated by the end of each year. The first auction will be open in the second quarter of 2016. The last one in 2021.

Except for a very few cases, all major renewable energy technologies will be eligible to bid into the auctions, provided that they meet formal criteria for auction entry set out in the new law.

The new law allows for participation only of ready-to-build power plants that have valid and binding construction permits and that have secured interconnection rights.

Bidders should bid the number of megawatt hours of energy to be supplied to the grid each year and the price. The bid price will be adjusted annually by the domestic inflation rate. Every bid must be supported with a deposit of PLN30 (US$7.80) for each kilowatt of capacity of the proposed power plant in the form of a cash deposit or bank guarantee. Bids can be submitted only by projects that have been pre-approved by the Energy Regulatory Authority.

Sponsors wishing to take part in 2016 auctions can apply for pre-approvals for their projects starting on May 1, 2015. The first auction will open no later than March 31, 2016 and, pursuant to the new law, will be done separately for projects above or below one megawatt in size.

Projects with capacities of at least 0.5 megawatts are expected to sell their electricity into the market. Sponsors will be solely responsible for entering into power delivery agreements.

If the price actually collected by a project is below the level offered in the auction, then OREO will pay the shortfall to the sponsor. However, OREO will not cover any shortfall below the weighted average price available at the power exchange for the particular day of power delivery. The power exchange is required to publish the weighted average price for each day.

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Thus, the transfer was fraudulent against the IRS.

Nebraska law allows a creditor to go after "the person for whose benefit the transfer was made."

The US Tax Court said the IRS could force the former shareholders to pay the amount they benefited — $58,842 — but not otherwise to pay the full taxes of the company.

The case is William Scott Stuart, Jr. v. Commissioner. *The Tax Court released its decision on April 1.*

MINOR MEMOS. The IRS has only 650 employees born in 1990 or later out of a total work force of 87,000. The agency is struggling after five straight years of budget cuts. It faces a long-term problem as a hiring freeze prevents it from replacing workers who leave . . . . US corporations now have $2.1 trillion in earnings parked in offshore holding companies, Bloomberg News reported after surveying US securities filings of 304 US multinational corporations. The earnings will become subject to US income taxes if repatriated to the United States.

— contributed by Keith Martin in Washington

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Under the new law, the designated major power purchaser must enter into the power purchase agreement on the same terms concerning price, volume and duration as in the bid that won the auction. Any shortfall payments by OREO will be distributed on a monthly basis. In order to qualify for shortfall payments, the renewable energy project must maintain a production level of at least 85% of the volume of total power production declared in the bid for three consecutive years. Failure to reach this level will subject the project to a penalty to be imposed by the Energy Regulatory Authority in the amount of 50% of the missing production volume multiplied by the bid price.

The new law carves out two renewable energy submarkets.

Poland is changing its support structure for renewable energy projects.

The first one is a micro installation market. The new law introduced a separate feed-in tariff system for small-scale power generating facilities up to three kilowatts and between three and 10 kilowatts of capacity. The law sets limits of, respectively, 300 megawatts and 500 megawatts of capacity in each of the bands that can be covered with this feed-in tariff sub-scheme. The intention is to encourage micro-power generation by individuals, who will be producing for themselves and selling any surplus power to the grid at the guaranteed price. This submarket will be filled on a first-come-first-served basis. Most of the capacity is expected to be taken up by photovoltaic panels. This creates an opportunity for photovoltaic panel vendors to sell into the Polish market, where PV facilities, even very small ones, are very rare today.

The second sub-market is for new renewable energy projects up to 0.5 megawatts in size. They will be given power purchase agreements for the accepted bid price and volume of power with a designated major power purchaser. The new law requires that 25% of power covered by the price guarantees must be produced by renewable power generating facilities with capacities of one megawatt or less. This is expected to lead to a significant new market for companies looking to develop projects on a scale of one megawatt or less, as it will be easier for such small projects to meet the formal requirements for entry into auctions (for instance, to secure connection rights and provide deposits) and the slice of market reserved for them is viewed as quite large.

Rush in 2015

The new law allows projects that deliver their first power to the grid by December 31, 2015 to be supported within the existing support system. Major power trading companies and other entities supplying final customers are required by law currently to purchase renewable power at a fixed price equal to the average market price of power produced from fossil fuels in the preceding calendar year.

This purchase obligation is combined with a duty to purchase special rights called "green certificates" that are issued to every operating renewable power producer. Power trading companies and other companies selling to final customers must purchase green certificates each year equal to a percentage of their customer loads. The price for the green certificates is subject to market conditions, so it can vary. A generator is also allowed to sell green certificates via the commodity power exchange, but this means it would take the full price risk.

The rapid expansion in renewable generating capacity led to a 40% fall in prices for green certificates during the period 2012 through 2014. Renewables industry players complained about the situation to authorities and lobbied for changes to limit volatility and the risk of low prices. The law made material modifications to the existing system, but did not go as far as the renewables industry wanted.

The new support system is limited to 15 years from the date of the first power delivery to the grid. There was no time limit on support under the old system.

The new law introduces certain tools to limit volatility in prices for green certificates. First, there will be a reduction in number of renewable power plants eligible for green certificates. Hydro power plants with capacities higher that five megawatts will no longer be entitled to receive green certificates.

Power plants using co-firing of fossil fuels with biomass, biogas or bioliquids must meet certain technical requirements concerning the fuel composition, and there are limits on the number of certificates to be issued for each megawatt hour produced. The percentage of total power sales that will carry a duty to purchase green certificates is 14% for 2015 and will increase to 15% in 2016 and 20% in 2017, but the Minister of Economy can lower this threshold if market conditions warrant.

Market Impact

The new law contains a number of features that will have a significant effect on the renewable energy market in Poland.

The new auction system has several advantages. The sponsor is guaranteed a subsidy to supplement the power price in a manner that is not available under the current green certificate system. The number of green certificates supporting existing renewable energy sources will be limited, which helps ensure a higher price for such certificates in the future. OREO will collect a special renewable energy fee from final customers in the future, thereby spreading the cost of supporting the renewable power industry across every power customer in Poland.

At the same time, the new system creates a number of challenges. Each sponsor must spend material funds to develop a project to a ready-to-build stage before the sponsor can bid. This investment has no guarantee of return, because it is subject to success in the auction. The reference price will be declared just two months before the auction, so it may turn out that the reference price is too low for some projects to remain economically feasible. The new law has guidelines for the government to take into consideration when setting the reference price. The government has been instructed to consider the reasonable actual project costs for every renewable technology. However, the language of the guidelines leaves considerable room for the government to maneuver.

The law imposes on sponsors a deadline of 48 months from the end of the auction to deliver the first electricity to the grid. Offshore wind power projects are granted 72 months for the first power delivery. At first sight, these look like challenging deadlines, but given that only ready-to-build projects can participate in the auctions, there may be enough time, provided the sponsor has also lined up financing.

The new support scheme favors investors with access to low-cost capital since they can bid the lowest prices.

A key feature of the new law is parallel systems of support. Projects that deliver power to the grid by the end of 2015 are grandfathered under the existing support scheme, but only for a period of up to 15 years from the first power delivery date. This should lead to a rush to build projects this year in order to stay in the green certificates system and have the option to stay in this system or try to win in a future auction and receive a shortfall price guarantee. Another incentive to complete projects in 2015 is the need to make first power delivery under the new support system within 48 months of winning at auction. Sponsors will have a one-time opportunity for the first three months after the new law takes effect to propose revised dates for first power delivery under existing interconnection agreements. Failure to meet the interconnection deadline will allow the system operator to terminate the interconnection agreement and claim damages from the sponsor.

The rush to commission projects in 2015 is expected to be followed by a standstill in construction of new projects in 2016 because of the timing of the new auctions. Next year will be devoted to work on bids for the first auction. The auctions will run through 2021. ◎

Turkish Solar Power: Better Late Than Never

by Ekin Inal, with the Bilgiç Attorney Partnership in Istanbul

Turkey has finally set the ball rolling on solar development, almost one year after the first license applications were received from developers. A new round of solar tenders is expected.

The Energy Market Regulatory Authority of Turkey received the first solar license applications in June 2013. No licenses have been issued to date. The Law No. 5346 on the Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy — the so-called renewable energy law — limits the total installed capacity of licensed solar power plants to 600 megawatts. The Ministry of Energy allocated this capacity to 27 regions. Of these 27 regions, Konya province has the largest allocated capacity with 92 megawatts in total, followed by Van and Ağrı provinces.

There was significant interest from both domestic and international sponsors in the June 2013 round of applications. A total of 9,000 megawatts of solar projects were proposed.

For most, if not all, regions, multiple solar power license applications were submitted for the same substation, and a tender will be required to determine the winning bidder. In the event of multiple applications, the state-owned electricity transmission company, TEİAŞ launches a tender in which bidders bid to pay TEİAŞ an amount per megawatt of capacity for the license, and TEİAŞ will award the license to the bidder offering the highest price. The price offered by the successful bidder will be paid to TEİAŞ within three years (at the latest) after the plant goes operational. Theoretically, if there are no competing bids for the same area or substation, applicants may proceed with the licensing and interconnection formalities.

TEİAŞ has launched three tenders so far. The first was held in May 2014 for Elazığ and Erzincan provinces in eastern Turkey. These two tenders were important, as the prices offered were expected to set a pattern for bids in the subsequent tenders. The winning applicant in Elazığ bid TL 827,000 per megawatt (US$321,000) and in Erzurum TL 68,000 (US$27,000). The difference in prices is mostly due to the higher solar irradiance in Elazığ compared to Erzurum. Although a difference was expected, the high price of TL 827,000 was not.

TEİAŞ conducted the second and third rounds of solar power tenders in late January 2015, covering southeastern and western regions of Turkey. Amounts bid by the participants were even higher than in the first round tender.

The January round of tenders was launched for the following regions.

No.	Name of Region/ Province	Allocated Capacity (MW)	Winners
1.	Konya-1	46	4
2.	Konya-2	46	6
3.	Antalya-1	29	2
4.	Antalya-2	29	2
5.	Burdur	26	2
6.	Muğla-Aydın	20	2
7.	Denizli	18	3
8.	Siirt-Batman-Mardin	9	1
9.	Şanlıurfa-Diyarbakır	7	1

Other than the regions numbered 8 and 9, which have a rather small capacity, there are sub-capacities allocated in other regions and, hence, multiple winners. It is no surprise that the highest bids per megawatt were submitted for the Konya region, a top region for investments with its vast flat lands: TL 2,510,000 or USD$1,013,000 per megawatt. What is surprising is the prices bid per megawatt, which are seen by sector representatives as exorbitant.

Economics

Turkey enacted some much-anticipated amendments to the renewable energy law in 2011 to put in place new feed-in tariffs and other incentives. The amendments provided feed-in tariffs for licensed renewable generators that opt into the "renewable energy support mechanism." They also introduced incentives for the use of domestically-manufactured components. The support mechanism refers to both parts: the feed-in tariffs and the incentives to use locally-manufactured components.

Power generators that wish to opt into the support mechanism for a particular year must apply to the Energy Market Regulatory Authority by October 31 of the preceding year. EMRA evaluates all complete applications and publishes a preliminary list of qualified applicants on its website by November 10. The application must cover the entire power generated by a facility from renewable energy sources. In other words, once a generator opts into the support mechanism, power generated based on renewable sources cannot be sold under any other transaction outside the support mechanism such as bilateral power purchase agreements. Therefore, every year, the generator will choose between the feed-in tariff and direct sales in the power market. Settlement of power sales under the support mechanism is coordinated by the Market Financial Settlement Center run by TEİAŞ.

Feed-in rates are valid for 10 years for power generators that commence operations by December 31, 2020. In addition to feed-in rates, renewable energy legislation provides for incremental price incentives for generators that use certain domestically-manufactured mechanical and electromechanical components in their facilities. Incentives for using domestically-manufactured components are available for five years after a project commences operations.

The table below shows the feed-in tariffs, as well as the maximum amount of domestic component incentive that can be obtained if all domestic components listed in the legislation are used in a solar power plant:

Feed-in Tariff	(US$/MWh)	Maximum Domestic Component Incentive (US$/MWh)	Maximum Total Price (US$/MWh)
Solar photovoltaic	133	67	200
Solar concentrated	133	92	225

For generators that use certain domestically-manufactured mechanical and electromechanical components in their projects, additional incentives are granted. In a photovoltaic power plant, the following components are granted the additional incentive:

Type of Domestic Component	Incentive (US$/MWh)
PV panel integration and manufacturing of solar structural mechanics	8
PV modules	13
Cells constituting PV modules	35
Inverter	6
Material that focuses solar ray on PV module	5
Total	**67**

The implementing regulation on domestic components requires that at least 55% of the components used in a solar facility must be locally manufactured. In order to reach this percentage, the regulation provides for different percentages for different parts, and if the total of these sum to 55% or more, then the generator is granted the incentive. For instance, in a PV module, glass is assigned 20%, frame 15%, back sheet 20%, junction box 20%, and ribbon 5%. If a generator uses locally-manufactured glass, frame and junction box, then it will be granted the additional US$13 incentive for use of locally-manufactured PV modules.

The legislation requires that components be actually manufactured in Turkey; mere assembly of parts is not sufficient.

In order to benefit from the domestic component price incentives, generators must submit two items to the Ministry of Energy. One is a "domestic manufacturing certificate" attesting to the domestic origin of the relevant component, to be prepared by a certified public accountant using a form provided in the regulations and approved by the Chamber of Industry or Chamber of Industry and Commerce with which the component supplier is affiliated. The other is a "product certificate" to be prepared by a national accreditation agency recognized by the International Accreditation Forum and attesting to the conformity of the component to national or international standards.

Currently, the local manufacturing sector is underdeveloped and generators are heavily dependent on imported products.

In addition, all renewable energy generators enjoy three other incentives, including reduced licensing fees and priority in grid connection.

The first is payment of only 10% of the license application fee otherwise applicable, and exemption, for a period of eight years, from the annual license fee.

The second is priority in grid connection.

The third is an 85% reduction in permitting costs, rent and other costs of gaining rights of access and usage of state-owned land (available only to projects that are in operation before December 31, 2015). The break on rent or easement fees runs for 10 years after a project commences operation.

In the wake of the significant amounts bid in the recent tenders, the solar power sector has been discussing how feasible the projects will be.

Most winners are subsidiaries of leading Turkish energy companies, but there are also international players. One might interpret this as a good sign that big players are ready to invest large sums to proceed with solar projects. / continued page 40

Turkey

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However, the sector's skepticism is understandable, especially in view of the bitter experience with wind power tenders a few years ago, where applicants ended up paying TEİAŞ large amounts of money that made their projects infeasible.

There are still 16 provinces or regions awaiting solar tenders.

Pre-Licensing Process

All generators are issued a preliminary license during the pre-construction stage that will be replaced by a permanent license at the beginning of construction. The winning bidders in the tenders that have already taken place will be granted pre-licenses.

Solar bidders had first to get an authorization from the Directorate of Meteorology to set up a measurement station on the site and then submit to EMRA measuring data of at least one year, including an on-site measurement conducted for at least six months, as part of their applications. The application package also includes a letter of guarantee in an amount calculated based on the contemplated installed capacity and the applicant's organizational documentation with the required statutory provisions. Applicants must be a joint stock company or a limited company.

During the pre-licensing period, the applicant must obtain the required permits, approvals and licenses to start construction such as zoning permits and environmental clearances, and also secure title to or a right to use the relevant land. No solar power plant is allowed on agricultural lands.

The pre-licensing period is 24 months, unless there is a force majeure event (unavoidable and unforeseeable events beyond the reasonable control of the generator, including acts of God and war) or the period is extended by EMRA, which has authority to extend for up to another 12 months. If the generator fails to secure the required permits, approvals or licenses within the pre-licensing term, then no permanent license will be issued.

No direct or indirect change in the shareholding structure of the generator is usually allowed during the pre-licensing period. Any such change will lead to revocation of the pre-license. However, a change is allowed in the shareholding structure of a foreign shareholder of the pre-license holder. For instance, shares in the foreign parent of a pre-license holder may change hands.

Once all obligations of the pre-license period are fulfilled, then the pre-license holder may apply for a permanent license. Such licenses are granted for a minimum of 10 years and maximum of 49 years.

There are also some share transfer restrictions applicable to license holders. Any direct or indirect acquisition of at least 10% of the shares of a licensed company (5% in public companies), or share transfers resulting in a change of control, require prior approval by EMRA.

The legislation grants a step-in right to lenders in limited or non-recourse project financings. Lenders may ask EMRA to approve the transfer of the license to another legal entity, provided that this entity assumes all the obligations of the related license holder.

Solar development is picking up speed in Turkey.

Distributed Generation

Another area of interest is distributed generation or so-called "unlicensed generation." As the name suggests, facilities with a generating capacity of up to a certain limit are exempted from pre- licensing requirements. The upper limit has been recently taken to one megawatt from 500 kilowatts, and the Council of Ministers, without any legislative amendment, is authorized to increase the limit up to 5 megawatts.

Solar power has been used for water heating for a long time in Turkey (without the need for any license or permit). In view of increasing electricity prices and falling cost of photovoltaic technology, Turkey has seen an increasing interest from commercial players and "prosumers" in roof-top installations.

In addition to exemption from licensing requirements, unlicensed generators are exempted from corporate formalities imposed on licensed generators. These generators do not have to establish a legal entity in order to operate. However, they must still obtain approval from the distribution company in the relevant region for grid connection and system usage and secure land use rights and environmental clearance. As far as these formalities are concerned, the renewable energy law does not distinguish between very small-scale unlicensed projects and larger projects, for example, one-megawatt projects.

Although the increase to one megawatt has been a positive development, Turkey has a long way to go to reach the level of distributed solar generation in other countries like the United States and Japan. Each unlicensed facility is required by law to be connected to a consumption unit, and any excess power not consumed in this unit can be sold to the grid. It is not clear whether the same generator may set up multiple facilities (for instance 10 facilities each having an installed capacity of one megawatt) within the same region, and sell the excess power to the grid. Normally a generator planning an installed capacity bigger than one megawatt would have to secure a license from EMRA. The legislation neither allows nor prohibits such structure. However, the legislation itself provides that, as a general rule, license-exempted generation must be used by consumers to meet their own power needs and not primarily for trading. Therefore, the structure involving multiple facilities with a maximum of one megawatt of installed capacity may be viewed by the authorities as circumventing the rules for licensed generation, and the structure has yet to be tested.

Power generated by an unlicensed facility and not consumed in the consumption unit can be sold to the grid, and this excess power will benefit from the feed-in rate and domestic component incentives, if applicable.

Unlicensed facilities may be transferred after provisional acceptance. A step-in right, as described earlier for licensed generation, is also possible for banks and other financial institutions that have provided limited or non-recourse project financing to the unlicensed generator.

What Lies Ahead?

Those who keep abreast of Turkish solar power are no strangers to government targets announced in multiple gigawatts to be reached by 2023, the centenary of the Turkish Republic.

The latest of these targets was announced in Turkey's first National Renewable Energy Action Plan prepared in line with the European Union's Renewable Energy Directive on the Promotion of the Use of Energy from Renewable Sources (Directive 2009/28/EC (1)), with support from the European Bank for Reconstruction and Development. According to the Turkish action plan, Turkey pledges to install 60 gigawatts in renewable energy capacity by 2023, five gigawatts of which will be solar.

It seems that Turkey's solar potential will finally be tapped. Turkey has an average annual total sunshine duration of 2,640 hours; a total of 7.2 hours per day, which gives Turkey the biggest potential among European countries after Spain.

Once the first pre-licenses are granted, the authorities are expected to launch a new round of license applications, and this time without the countrywide limit and with a faster process.

The real hurdle ahead for solar power is not the investment costs (which have been decreasing due to advancement of photovoltaic technology), but the 600-megawatt countrywide limit. The local manufacturing sector is also expected to grow after the pre-licenses are granted and investors have a clearer view of the solar power market in Turkey.

Growth in rooftop solar installations is expected to continue. It is still not clear whether the regulators will require aggregation of multiple small generating facilities with a single owner in the same general location for purposes of limiting access to net metering where excess generation is sold to the grid. However, more investment (both domestic and international) is expected.

A New Geothermal Framework For Mexico

by David Jiménez and Javier Félix, in Mexico City, and Raquel Bierzwinsky, in New York

Mexico has a new law to regulate geothermal exploration, drilling of geothermal wells and the use of geothermal steam or fluid to generate power.

Regulations issued in late 2014 to implement the new law address the legal, technical, administrative and financial requirements, as well as the procedures necessary, to obtain a registration, permit or concession.

Mexico has adopted new rules for geothermal companies.

Three Activities

Mexico treats geothermal activities as falling into three broad categories, each of which is regulated. The three are reconnaissance, exploration and production. Use of subsurface land for geothermal projects has priority over any other use of the land, including mining, but not over activities pertaining to the hydrocarbons industry.

"Reconnaissance" refers to scouting sites and deposits and conducting surveys for possible drilling.

Mexican law allows private individuals and companies incorporated under Mexican law and the *Comisión Federal de Electricidad* or CFE and other state productive enterprises to engage in reconnaissance, but they must register first with the Ministry of Energy. The registration involves submitting evidence of an applicant's legal, technical and financial capacity. Once registered, an applicant has eight months to do the reconnaissance before the need to update the registration.

"Exploration" is test drilling and any other work above or below ground to confirm the existence of a geothermal resource and identify the boundaries of a geothermal area.

Exploration requires a permit from the Ministry of Energy.

A company should apply for a permit two months before the registration for reconnaissance activities expires. The permit requires the same showing of legal, technical and financial capacity as well as the technical feasibility of the project. An applicant must also submit a technical exploration plan with scheduled milestones and a financial plan with details of the proposed investment at each stage of the project.

Permits do not grant real estate rights to their holders; rather, they only grant a temporary right to explore the geothermal resource.

Permits may be issued for areas of up to 150 square kilometers and may be valid for three years. They can be renewed for another three years after the initial term. Studies of the explored reservoir and other information provided to the Ministry of Energy by the permit holder are confidential for as long as the permit remains in effect.

"Production" refers to any activities after the production wells start producing and the steam or fluid is used to generate electricity or is sold in the market for other uses.

Production requires a production concession from the Ministry of Energy. Such concessions are only given to holders of exploration permits. The concession cannot exceed the area covered by the exploration permit. A geothermal concession grants an exclusive right to use the geothermal reservoir in the concession area, but does not grant any real property rights in favor of the concession holder.

Production concessions are valid for 30 years and may be extended at the request of the concession holder with the approval of the Ministry of Energy.

The Ministry of Energy may reclaim a concession where there are risks to the population or the environment or for national security reasons.

The holder of a concession can assign its rights and obligations under the concession to a third party, but this requires prior authorization of the Ministry of Energy. Only a notice to the Ministry is required for an assignment to an affiliate

To obtain a production concession, the applicant must also have a power generation permit from the *Comisión Reguladora de Energía*, get confirmation of interconnection feasibility from the independent system operator — CENACE — comply with environmental requirements and pay any applicable fees.

Other Issues

The Ministry of Energy must put out for public bid any concession that terminates, lapses or is revoked due to failure of the concession holder to comply with conditions.

Holders of exploration permits and production concessions must provide financial guarantees. Permit holders must deliver and maintain for the term of the permit a performance guarantee for 1% of the financial plan proposed in the exploration schedule. Concession holders must deliver and maintain, until commercial operation has been achieved, a performance guarantee for 0.5% of the aggregate required investment. All guarantees and bonds must be issued by Mexican financial institutions and be payable to the order of the Mexican federal treasury.

The new geothermal law regulates not only the exploration of hydrothermal geothermal reservoirs, but also the use of geothermal water. A permit holder for a hydrothermal geothermal reservoir must drill one to five exploration wells, with the number to be determined by the Ministry of Energy based on the size of the permitted area and the corresponding technical studies. Any geothermal water extracted during exploration must be re-injected into the ground to maintain the renewable nature of the resource.

The regulations distinguish between production concessions for geothermal reservoirs and concessions for the production and use of the subsurface waters in such reservoirs. Given that each concession serves a different purpose, different rules, terms, conditions and processes apply to each. Concessions for geothermal waters are regulated by the National Waters Law, rather than the new geothermal law, and must be obtained from the *Comisión Nacional del Agua*.

The new law grants CFE the right to select certain areas for its exclusive exploration and production of geothermal resources upon request to the Ministry of Energy, so long as it provides evidence that it can develop the areas efficiently and competitively. CFE had until January 30, 2015 to provide the Ministry of Energy with a list of such areas for development. However, it may still choose to develop them jointly with the private sector. The Ministry of Energy has until May 30, 2015 to respond to CFE's requests.

The new law allows CFE to develop new projects jointly with the private sector or to bid them out for exclusive development by the private sector.

Any party who was already engaged in geothermal exploration or production at a site in Mexico before the new law was enacted, and who did not need a concession, registration or permit under the National Waters Law, may continue with its project, provided it notified the Ministry of Energy of its activities within 30 business days after the new law was enacted.

Anyone holding a concession granted under the National Water Commission when the new law was enacted will be grandfathered from the need to get a permit or concession under the new law.

A new geothermal project goes through three phases, each of which requires separate permits or concessions.

Mozambique's Rovuma Basin LNG Regime

by Kevin Atkins, Julien Bocobza and Alex Neovius, in London, with the assistance and co-operation of AG Advogados (in association with F. Castelo Branco & Associados), in Mozambique

After much waiting, the government of Mozambique has taken a huge step toward monetizing its much-publicized gas reserves by publishing the eagerly-anticipated legal framework for the development of an LNG project in the deepwater Rovuma Basin offshore Mozambique.

The discovery of gas reserves in the Rovuma Basin has transformed the domestic Mozambican upstream sector and given Mozambique some of the largest gas reserves in the world, potentially making it the third largest exporter of LNG behind Qatar and Australia. (For earlier coverage, see "Mozambique's New Petroleum Regime" in the November 2014 *Newswire* starting on page 55.)

This article looks at some of the key changes brought about by the new Rovuma Basin law and draws on an English translation of the new law kindly provided by AG Advogados (in association with F. Castelo Branco & Associados), who have co-authored this article and provided Mozambique law input.

Applicability

The new law applies to all the existing concessionaires in Areas 1 and 4 offshore Mozambique, as well as any special-purpose vehicles (SPVs) they may establish and any contractors engaged by them in relation to the "design, construction, installation, ownership, financing, operation, maintenance and use" of project infrastructure necessary for the "extraction, processing, liquefaction, storage, transportation, delivery and sale" of gas discovered in Areas 1 or 4. However, the new law also includes a catch-all provision that extends its application to any other person directly involved in any of the foregoing.

All SPVs established by concessionaires must be incorporated in Mozambique, although SPVs for the purposes of raising finance or undertaking sales and shipping activities may be incorporated in any "transparent" jurisdiction where the government of the jurisdiction can verify the ownership, management, control and fiscal situation of the investor (subject to Mozambique government consent). While this "transparent" jurisdiction standard is equivalent to the standard imposed on new concessionaires under the new general petroleum law of August 2014 (Law No. 21/2014), unlike the requirements of the new petroleum law, neither the existing concessionaires of Areas 1 and 4 nor their SPVs are required to be listed on a stock exchange.

The consent of the Mozambique government will be required prior to any transfer of shareholdings or change of control of any SPV (although any such transfer or changes effected by way of enforcement over a security interest granted as part of a financing does not require prior consent, as financing structures are subject to the prior approval of the government at the outset). However, the new law does not set a minimum threshold and, accordingly, any changes in shareholding (even minority interests) will require prior consent from the government. Given the scope of what constitutes an SPV, this restriction will likely apply to indirect changes, too, where shares in intermediate holding companies are transferred. The prior consent of the Mozambique government will also be required upon any amendment to the constitutional documents of any SPV, which could prove to be a burdensome ongoing corporate obligation in light of a 30-year project lifespan, particularly as and when equity participants look to take stakes in the project and seek to include operational

Mozambique has set a legal framework for an offshore LNG project.

and governance controls within the terms of constitutional documents.

In either case, the consent of the government must be granted within 10 days of application, although there is no explicit concept of deemed consent if such consent is not granted within the 10-day time period, nor is there any reference to what happens if neither a consent nor a refusal is communicated to the applicant.

Stabilization

A key principle in the new law is the legal and fiscal stabilization available to concessionaires to preserve the legal regime for the project. However, concessionaires are not protected from changes in law that result in an annual change not exceeding US$5 million in the aggregate, nor are they protected from other changes to health, safety and environmental legislation, provided such changes are non-discriminatory and consistent with international standards (although that is itself a fairly ambiguous and frequently-challenged standard).

Where any of the non-excluded changes are brought about, the government must restore the concessionaires to the position they would otherwise have been in if the changes had not occurred. If the concessionaires and the government cannot agree within 90 days on those required restoration steps, then an independent expert will determine the steps for them.

Additionally, the concessionaires are entitled to a 10-year fixed rate of petroleum production tax payable in relation to the project. The rate is currently 2%. The rate will be examined and adjusted by mutual agreement with the government within 90 days of the 10th anniversary and again on the 20th anniversary of the first shipment of LNG from the project, provided that where no such agreement is reached, the rate of petroleum production tax will increase to 4% on the 10th anniversary and to 6% on the 20th anniversary.

This system, the so-called "meet-to-disagree" system, was included in the new law as a compromise to ensure the new law complies with the legislative authorization that enabled the government to pass the new law in the first place. The legislative authorization provides that the fiscal stabilization provisions should be renegotiated every 10 years, without affecting the profitability and feasibility of the project. At the same time, these fixed figures should enable concessionaires to factor the tax take into their project economics and maximize the cost recovery for the financing and capital expenditures.

Finally, the new law stipulates that the contracts or agreements to which the government is a party and the rights relating to the Rovuma Basin project may only be modified or terminated by mutual agreement in accordance with the respective contractual terms and conditions, thereby constituting an exception to the general regime of the Public Administration Law of August 10, 2011 (Law No. 14/2011), which provides that the government is entitled unilaterally to modify or terminate contracts under certain conditions.

Straddling Reservoirs

In addition to the development of gas deposits located exclusively within either Area 1 or Area 4, the new law also expressly authorizes the development of 24 trillion cubic feet (or 680 billion cubic meters) of gas located in fields that straddle the boundaries of Areas 1 and 4.

For these straddled reservoirs, the concessionaires are required to submit a proposed unitization agreement and a development plan to the government within six months after the date the new law was published. Where this is not satisfied, an independent expert will be appointed to determine the terms of the unitization agreement within 12 months after the date the new law was published. A heads of agreement was signed in December 2012 proposing separate but co-ordinated development of these straddled reservoirs, with the operator of each area being responsible for development of the straddled reservoirs lying within the boundaries of its Area, although a formal unitization agreement and joint development strategy have not been agreed.

Given the scale of deposits that straddle Areas 1 and 4, a co-ordinated development effort is fundamental to achieving a successful LNG project and maximizing recovery of available reserves; hence the emphasis in the new law on unitization and joint development.

LNG Infrastructure

The concessionaires must also deliver to the government, within six months after the date the new law was published, a joint plan for construction, development and operation of an LNG terminal and related infrastructure on the Afungi peninsula in the Cabo Delgado province of northern Mozambique, and the offshore infrastructure connecting to the LNG terminal.

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Mozambique

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The concessionaires are authorized to design, construct, install, own, finance, encumber and use the LNG terminal and, in tandem with port authorities, will have responsibility for controlling and directing maritime traffic inbound to, and outbound from, the LNG terminal pursuant to a new separate concession to be awarded to the Area 1 and Area 4 concessionaries.

However, the materials offloading facility that is needed to allow for offloading of materials required to construct LNG facilities will be managed and operated by a new special-purpose joint venture owned 30% each by the operators of Area 1 and Area 4 and 40% by Portos de Cabo Delgado, S.A. (a state-owned entity established as a 50-50 joint venture between ENH, the Mozambican national oil company, and CFM, the Mozambican regulatory body for ports and railways). Additionally, upon release of the construction completion guarantees for the first four LNG trains (out of a possible 10-train project), a new separate concession for the materials offloading facility will be awarded to the joint venture, with the principle being to ensure that the concessionaires have control over the construction phase of the materials offloading facility as this will inevitably affect progress of the entire Rovuma Basin project.

The new law also requires the concessionaires to involve personnel from Portos de Cabo Delgado, S.A. in operations for the loading of LNG vessels and to permit such personnel to have access to the LNG terminal from time to time to monitor the volumes loaded. While the effectiveness of the required joint venture structure remains to be seen, the intention clearly seems to be to enhance local content participation, train Mozambican citizens and increase local industrial know-how. However, the involvement of a separate independent 40% shareholder in the holder of the concession for the materials offloading facility, at a time when a substantial number of LNG trains are yet to be constructed and the material offtake facility will remain in considerable use, may lead to issues when negotiating O&M service fees payable to the joint venture, as the interests of the 40% shareholder may not always be aligned with the interests of the concessionaries.

The new law also requires that ENH be involved in operations under the new separate concessions awarded for the materials offloading facility and the LNG terminal. Although the extent and scope of this involvement is unclear, local sources have interpreted the obligation as being satisfied through ENH's participating interest in Portos de Cabo Delgado, S.A. and not as an additional obligation that could give ENH a potential right to delay project development and extract fees along the value chain of the project.

Third Party Access

Similarly to the provisions of the new general petroleum law of August 2014, concessionaires are required to grant third parties access to their LNG infrastructure where there is available capacity and the access would not be adverse to concessionaires. However, unlike the new general petroleum law of August 2014 (and, in fact, the prior Mozambican petroleum law of 2001), there is obviously no obligation on the concessionaires to expand their facilities at the cost of the third party if there is insufficient available capacity to accommodate their volume demands.

Development and Production

The government has nine months from receipt of a development plan to approve the plan or notify the concessionaires of deficiencies that require amendments to the plan. Upon receipt of a notification of deficiencies, the concessionaire will have 45 days to make the required amendments to the plan and resubmit the amended plan to the government after which the government will have another month to approve or reject the amended plan. This nine-month approval period may delay the ability of concessionaires to achieve their final investment decisions during 2015 if development plans were not submitted by the end of March 2015.

Once a development plan has been approved by the government, concessionaires have a 30-year development and production period for their LNG projects. Gas sales contracts require the prior approval of the government, although the government can delegate to ENH the authority to approve gas sales contracts with a term of 12 months or less to ENH. This may give ENH visibility into pricing formulations and the strategic decision making of the concessionaires, which may consequently affect any negotiations between ENH and the concessionaires for domestic supply obligations.

Such approval rights could fetter the rights of concessionaires to sell their gas to whichever buyers and on whatever terms they see fit, as the government may be primarily concerned with maximizing the revenue stream generated by such gas sales while the concessionaire will have broader issues and commercial relationship matters to consider with each offtaker. Additionally, despite the lack of a formal domestic supply obligation under the new law, it is possible that the government approval right for gas sales contracts could be manipulated to ensure that all gas sales are to a local offtaker. Thus, the government could refuse to approve any sales contracts that are not with local offtakers.

Neither the new law nor the existing exploration and production concession contracts set out domestic supply obligations. However, as development plans are required to allocate some gas to the domestic market, the allocated volume is expected to be negotiated during approval of the development plan.

Tendering and Procurement

Concessionaires are required to file a local content plan in conjunction with development plans to be approved by the government. The local content plans must be updated every three years. As part of each local content plan, preference shall be given to Mozambican personnel or entities where the services offered by them are comparable to those available in the international marketplace and their prices do not exceed those of the international marketplace by more than 10% (except for specialized services relating to technology and intellectual property).

Mozambique could become the third largest LNG exporter behind Qatar and Australia.

Except in very limited circumstances, such as emergency or failure to meet tender requirements or in the case of highly-specialized equipment, contracts with a value in excess of US$3 million must be tendered, with contracts having a value exceeding US$3 million but less than US$25 million requiring notification to, but not prior approval from, the National Petroleum Institute, and contracts having a value of US$25 million or more requiring prior approval from the National Petroleum Institute.

Concessionaires are also required to provide the Bank of Mozambique with a detailed list each quarter of contracts with international suppliers.

The selection of lenders and financing parties is not subject to any tendering obligation.

Financing Structures

The new law grants concessionaires full rights to mortgage and secure LNG infrastructure and project assets for the purpose of raising finance for projects.

Financing structures require prior approval of the government, although once such approval is obtained, there are no requirements or restrictions on the concessionaires as to the identities of lender institutions. Concessionaires have full flexibility to adopt whatever arrangements they find most suitable and may obtain financing from lenders within or without Mozambique and may adopt whatever debt-to-equity or capital adequacy ratios they see fit. This flexibility is likely to be a necessity given the scale of development and capital expenditure required for each project.

The requirement that the government approve financing arrangements for each project undertaking may obviously affect project timing, although it will be in the government's best interests to approve financing arrangements as quickly as possible in order to accelerate project development. However, an upfront government consent requirement at the outset of each such undertaking should facilitate smoother processes for security arrangements, as the initial government consent will constitute the consent required to implement the grant of any security interests, with no further consent required either to perfect or even to enforce security interests upon a default.

The new law also includes a commitment by the government to support such financing arrangements, once approved, by executing direct agreements required by lenders and even refers to the customary step-in and remedy rights available to lenders.

Other Issues

Perhaps most importantly from a / *continued page 48*

Mozambique

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financing perspective, concessionaires are permitted to open up offshore collection accounts for receivables and project revenues to be paid and out of which loans may be amortized.

However, capital operations, such as entry into loans and the provision of related guarantees or security, are subject to prior approval from the Bank of Mozambique which, if not granted within five business days after the request, will be deemed granted. Any disbursements and cash funding out of the proceeds of any such loans will need to be registered with the Bank of Mozambique, but will not require any prior authorization.

Monthly bank statements for offshore collection accounts must be provided to the Bank of Mozambique and the National Petroleum Institute who are entitled to audit the accounts annually.

However, sums required to satisfy domestic Mozambican obligations, such as taxes and domestic goods and services and personnel, must be transferred from the offshore collection account into an onshore Mozambique account, and 50% of such sums must be converted into metical, the Mozambican currency. Foreign direct investments must be registered with the authorities within 10 days of the investment being made in order to extract cash and remit profits resulting from such investments.

Given the importance of the Rovuma Basin project and the impact it is expected to have on the local economy, the new law provides that it is in the national interest that antitrust restrictions not apply to project operations. Accordingly, the Rovuma Basin project is excluded from any applicable Mozambican antitrust legislation.

As with the procurement obligation, concessionaires are required to give priority to the employment of Mozambican nationals in the project work force. In particular, foreign individuals must not be preferred for roles with less technical complexity.

Additionally, as part of their development plans the concessionaires must propose a quota of aggregate foreign individuals in the project work force at any one time that will be updated annually and approved by the government. Hiring more foreign workers than this agreed figure will be difficult unless the individuals are hired on a short-term basis for 180 days or less (although visas will typically only allow stays of up to 90 days) or the prior approval of the government is obtained specifically authorizing the employment of the identified workers.

Concessions are being granted for gas development in the deepwater Rovuma Basin.

Normal daily working hours are also increased from eight to 12 hours and concessionaires are given flexibility to implement different working periods, provided a suitable rest period is offered to the workers after the work period. This gives concessionaires more opportunity to advance development operations and offer competitive working schedules to incentivize workers and accelerate project timelines.

The new law provides that ENH and other state-owned companies may submit to international arbitration any disputes arising from the existing exploration and production concession contracts or from any other agreements related to the Rovuma Basin project. This is expected to be extremely advantageous as the Law on State Enterprises that applied previously prohibited state-owned companies from entering into arbitration agreements and, thus, restricted the rights of investors to seek independent and neutral arbitral recourse. ◎

Environmental Update

The US Environmental Protection Agency announced earlier this year that it would delay finalizing both its rule to control carbon dioxide emissions from new power plants and its "Clean Power Plan" rule to reduce emissions from existing or modified power plants until sometime this summer.

The agency said the delay is necessary because new issues have been identified that will have to be addressed by better coordinating these different rules. It also said it will issue a model federal implementation plan for states to follow as a guide to drafting their own state implementation plans for existing and modified plants.

Since these announcements, EPA has continued to push each state to develop its own unique plan to comply with carbon dioxide standards for existing and modified power plants, rather than ultimately subjecting themselves to a federal implementation plan. This is because a number of Republican officials and agency detractors have urged states to "just say no" and refuse to comply with the federal plan once it is finalized.

Senate Majority Leader Mitch McConnell (R-Kentucky), for example, has urged states to "carefully review the consequences before signing up for this deeply misguided plan."

Other critics are suggesting that EPA lacks statutory authority to require power plants to do more than simply improve how efficiently they operate.

The Clean Power Plan sets a different carbon dioxide emissions rate for each individual state. States can develop their own plans for how to comply. The federal government could impose its own model plan on states that fail to establish their own plans to meet emissions targets.

Industry Guidance

The American Wind Energy Association and the Solar Energy Industries Association published a handbook on March 30 suggesting how states might comply with the Clean Power Plan by switching to renewables to cut carbon emissions from existing power plants.

The handbook, "Incorporating Renewable Energy into State Compliance Plans for EPA's Clean Power Plan," gives an interpretation of the draft EPA rule and technical support documents and offers step-by-step guidance to states on how to incorporate renewable energy into their state compliance plans.

It points states to renewable integration studies suggesting wind and solar energy can be added to the power system without harming reliability, a concern raised by critics of the Clean Power Plan. The handbook says the cost of wind energy has fallen by more than 50%, and installed solar system prices have dropped by 49%, since 2010.

It also provides state officials with guidance on calculating carbon reductions from wind and solar energy and on tracking the reductions. The two trade associations say they will update the handbook after EPA releases its final rule this summer.

Northern Long-Eared Bats

The US Fish and Wildlife Service said April 1 that it is listing the northern long-eared bat as merely "threatened" rather than "endangered" under the Endangered Species Act.

The bat was originally proposed for listing as "endangered" in 2013 due to a severe decline in the species caused by white-nose syndrome, a fungal disease affecting cave-hibernating bats. The bat is found in 37 states, from Maine to North Carolina along the east coast, west to Oklahoma and north into the Dakotas, Montana and Wyoming, as well as 13 Canadian provinces. White-nose syndrome has been confirmed or is suspected in up to 28 states, with particular devastation reported in the northeast.

The US Endangered Species Act prohibits any harming, harassing or killing of both endangered or threatened species unless an "incidental take" permit has been issued.

When a species is listed merely as threatened rather than endangered, the Fish and Wildlife Service may issue general rules of limited scope to protect the species. The agency issued an "interim rule" and is accepting public comments through July 1, 2015.

Under the interim rule, all purposeful taking would be prohibited in all states where the bat is located except for taking associated with removing the bat from human structures. For areas of the country affected by white-nose syndrome, the new rule would further prohibit all unpermitted incidental takes with some exceptions. The exceptions — where an incidental take permit is not required — include forest management practices, maintenance and limited expansion of transportation and utility rights-of-way, removal of trees and brush to maintain prairie habitat, and limited */ continued page 50*

tree removal projects, so long as these activities protect bat maternity roosts and hibernacula.

The strictest restrictions would apply during the two-month pup-rearing season in June and July when the bats occupy their hibernacula and are most vulnerable.

Incidental takes of the northern long-eared bat in wind, solar, mining, construction, agricultural, and oil and gas activities are exempted only in parts of the country not yet affected by white-nose syndrome — most commonly in the bat's western range. In other parts of the country, an incidental take permit is required for any takes in connection with these activities.

The interim rule will be effective starting May 4, 2015.

Indiana Bats

A federal district court in mid-March upheld the US Fish and Wildlife Service's issuance of an incidental take permit for the killing of a limited number of endangered Indiana bats at a 100-turbine wind farm proposed for Champaign County, Ohio. The project is called Buckeye Wind.

A non-profit group, Union Neighbors United, that was formed to fight the project challenged the finding by the US government that the take permit will minimize and mitigate the effects on bats "to the maximum extent practicable."

The Indiana bat has long been protected as an endangered species. Concerns for its future have increased in recent years due to the spread of fungal white-nose syndrome to hibernating bat populations. No Indiana bat hibernaculum are reported in the immediate vicinity of the Buckeye project, but operation of its wind turbines has the potential to "take" Indiana bats that migrate through the area in the spring and fall.

Buckeye proposed various steps to minimize the harm to bats from its project, including varying the wind speed at which its turbines will rotate to minimize the number of bats that collide with the blades during key times of the year. The project will be required to do ongoing monitoring and will acquire and protect approximately 200 acres of bat habitat.

The Fish and Wildlife Service approved a five-year take limit of up to 26 takes or 130 over a 25-year period.

In upholding the permit, the court rejected the claim by the non-profit group that the agency is required by law to select a project alternative that minimizes the taking of Indiana bats to the "maximum amount that can be implemented by the applicant" before applying mitigation measures to offset any take that could not be avoided or minimized.

The court said the law "permits an agency to place less emphasis on whether a program is the 'maximum that can practically be implemented by the applicant' if an applicant can first demonstrate that the minimization and mitigation provide substantial benefits to the species.

The agency had decided, before issuing the incidental take permit, that the minimization and mitigation measures proposed by the project company "fully offset" the impact of taking Indiana bats, and, thus, the court said, it was unnecessary to determine whether the plan was the "maximum that can be practically implemented by the Applicant."

"Once the impact was fully mitigated," the court said, "it was not necessary for [the Fish and Wildlife Service] to determine whether more mitigation was possible, or whether the impact could possibly be minimized further."

Trends in Wildlife Regulation

Although Buckeye still faces additional hurdles, there are lessons the wind industry and those who finance wind projects can take away.

The Fish and Wildlife Service appears to giving the most negative attention to utilities that ignore the agency's land-based wind energy guidelines and site-specific agency recommendations. The reverse appears true as well: the agency is more lenient with developers who take such steps early even when problems arise later.

This trend extends beyond endangered species issues to all federal wildlife laws, including the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act.

The reason is simple. Because construction and siting of wind farms are generally approved at the local level, the federal role is often limited to offering recommendations and then imposing fines against utilities found to have taken endangered species or protected habitat without a permit. The Fish and Wildlife Service likes to see wind developers take a variety of early steps, including survey work to assess risk and inform project adjustments, such as adjusting turbine speeds during migration season and delaying cut-in until the winds are stronger and fewer birds or bats are flying, or by making power lines and project facilities less attractive as perches.

The Buckeye litigation shows the potential benefits from working with the agency in siting a facility and then keeping in touch throughout the permit process, if needed, to establish mitigation measures and best management practices that minimize project impacts on threatened and endangered species. In contrast to agency treatment of what it considers "bad actors," meaning those who do not follow the guidelines, developers who demonstrate good faith have less to fear from agency enforcement when issues arise.

Mercury

The US Supreme Court heard oral arguments in late March on whether the Environmental Protection Agency violated the Clean Air Act when it decided not to consider the financial costs of its regulations limiting emissions of mercury and other toxic air pollutants from power plants. The regulations in question are the 2012 mercury and air toxics standards, or MATS.

The consolidated case before the court is Michigan v. EPA. Various states and industry groups are arguing that the government's decision not to consider cost was arbitrary and has led to a regulation with disproportionately high compliance costs of over $9 billion annually.

The government is arguing that section 112(n)(1)(A) of the Clean Air Act requires the EPA to assess and potentially regulate air toxics emissions from power plants, but does not explicitly require the agency to consider cost.

The Supreme Court is reviewing a narrow portion of a 2014 appeals court decision that upheld the MATS rule after concluding that EPA's decision-making was reasonable and that the agency deserves deference. A decision is expected by June.

Carbon Emissions

President Obama released a blueprint at the end of March for cutting US greenhouse gas emissions by nearly a third over the next 10 years. The plan is being submitted to the United Nations in advance of a summit in Paris in December at which negotiators hope to reach a global climate change agreement.

The blueprint follows up on the joint climate change reductions pledged by the presidents of China and the United States -— the world's two largest greenhouse gas emitters — in Beijing last November. At that time, President Obama said the US would cut emissions 26% to 28% by 2025, and President Xi Jingping said that China's presently escalating carbon dioxide emissions would peak by 2030 or earlier and pledged to increase China's share of non-fossil fuels energy consumption to approximately 20% by 2030.

The release of the blueprint is supposed to show how the Obama administration intends to meet the US pledge and is intended to motivate other global emitters to make similar substantive pledges in advance of the Paris talks. The goals the US announced would not require any action by the US Congress. It relies on steps the administration can take on its own, such as the Climate Action Plan (for reducing carbon emissions from existing and modified power plants) that the administration is in the process of finalizing. Existing coal-fired power plants are the chief source of US carbon emissions.

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EPA will release a model plan for states to reduce carbon emissions from existing power plants.

Environmental Update

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Environmental groups have both praised the blueprint as a necessary first step and criticized it for not achieving deep enough reductions. At the same time, Republican leaders and climate change deniers have attacked the plan as harmful to the economy. The Senate majority leader, Mitch McConnell, said, "Even if the job-killing and likely illegal Clean Power Plan were fully implemented, the United States could not meet the targets laid out in this proposed new plan." He warned other countries not to believe what is in the blueprint. "Considering that two-thirds of the U.S. federal government hasn't even signed off on the Clean Power Plan and 13 states have already pledged to fight it, our international partners should proceed with caution before entering into a binding, unattainable deal," McConnell said.

— contributed by Andrew Skroback in Washington

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