chadbourne

PROJECT FINANCE
NewsWire

February 2016

Cost of Capital: 2016 Outlook

More than 2,000 people listened in January as a group of project finance industry veterans talked about the current cost of capital in the tax equity, bank debt, term loan B and project bond markets and what they foresee for the year ahead.

The panelists are John Eber, managing director and head of energy investments at J.P.Morgan, Jack Cargas, managing director in renewable energy at Bank of America Merrill Lynch, Thomas Emmons, managing director and head of renewable energy finance for the Americas at Dutch bank Rabobank, Jean-Pierre Boudrias, managing director and head of project finance at Goldman Sachs, and Jerry Hanrahan, vice president and team leader, power and infrastructure, North American corporate finance at John Hancock. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: John Eber, what was the tax equity volume in 2015, and how did it break down among wind, utility-scale solar and rooftop solar?

Tax Equity

MR. EBER: We estimate that about $11.5 billion in new wind and solar deals were mandated in 2015. Of that amount, about $6.4 billion was wind. There were 40 wind projects with an aggregate capacity of 5,700 megawatts, which is the same number of projects in the previous year, but an increase of about $700 million in tax equity raised in 2015 over 2014.

There were three leading sponsors in the wind sector that did about $1 billion each. They accounted for about 47% of the total wind tax equity raised.

The solar market is not as transparent as wind, but we estimate that about $2.6 billion in tax equity was raised in the residential rooftop market by the three / continued page 2

IN THIS ISSUE

IN OTHER NEWS

NEW COMMERCIAL PPAS signed in 2015 reached 3,160 megawatts, more than double the year before.

Further growth is expected in 2016. The contracts, with data centers, factories and other large consumers of electricity, are a welcome alternative for project developers struggling to find US utilities willing to sign long-term power purchase agreements. The American Wind Energy Association reports that of the 1,800 megawatts of power purchase agreements signed by US wind developers in Q4 2015, roughly 75% were commercial PPAs.

/ continued page 3

Cost of Capital

continued from page 1

leading residential rooftop companies. That is up from about $1.9 billion in 2014. The top three sponsors account for about 90% of the residential market.

Another $2.5 billion in tax equity was raised for utility-scale and commercial and industrial solar projects. The solar figures are rough estimates.

MR. MARTIN: So there was only a modest increase in tax equity volume in 2015. In 2013, the total volume was $6.5 billion. In 2014, it was $10.1 billion. Why was there a slowing down in the rate of increase?

MR. EBER: The increase was still significant in absolute numbers because it comes off a huge year in 2014. These are historically significant numbers.

MR. MARTIN: How many active tax equity investors are there currently?

MR. EBER: We estimate about 20 in wind and 27 or 28 in solar. However, of the 20 in wind, we identified only 17 who actually entered into mandates in 2015.

MR. MARTIN: There is overlap between the two. How many total investors were there in 2015?

MR. EBER: No more than 30.

MR. MARTIN: Jack Cargas, what do you expect in the year ahead: deal volume, number of investors, mix of transactions, mix of structures?

MR. CARGAS: The volumes are likely to be similar to what we have seen in the last couple years.

In terms of transaction types and structures, the partnership flip structure will continue to be the leading application. There are lots of variations in the basic structure.

We expect to see similar volumes as in 2015 in wind and residential solar and a possible increase in the volume of utility-scale solar as there are some significant utility-scale solar projects that are expected to come to the market in 2016.

It would not be terribly surprising to see a further increase in the number of tax equity investors. The number increased in each of 2014 and 2015. The tax credit extensions in December may bring other investors into the market.

MR. EBER: I agree. The market should remain very active in 2016. Wind developers will feel more pressure to get projects underway in 2016 to qualify for full tax credits. Wind projects that start construction in the next three years after 2016 still qualify for credits, but at reduced levels. Solar developers may not feel as urgent a need to act in 2016 as they have until December 2019 to start construction and qualify for full tax credits and another two years after that to qualify for reduced credits.

MR. MARTIN: Many people expect that there will be a reduction in 2016 deal volume due to the tax credit extension since there will be less pressure to complete projects in 2016. It does not sound like either of you agrees with that.

MR. EBER: A lot of the commitments by tax equity investors are made well before a project is completed. Developers who plan to begin constructing projects and investing money in them will be in the market seeking tax equity commitments even though a project may not be completed until 2017. That will keep us busy this year.

Wind and solar tax equity volume was $11.5 billion in 2015 compared to $10.1 billion in 2014.

MR. CARGAS: Sponsors will not have to commit unnatural acts to complete projects in 2016. Some of what would have been completed in 2016 before the extension will now be spread into 2017.

MR. MARTIN: A lot of deals carried over into the start of 2015 as tax equity and due diligence shops had too little capacity in late 2014 to handle the volume. Did you see the same thing happen at the end of 2015?

MR. EBER: Not so much. It helped that more firms were offering engineering services. Many of us were better staffed last year in anticipation of the need. We were very busy all through the year and especially in the fourth quarter, but we managed to get everything processed that our clients wanted to close in 2015.

MR. MARTIN: Jack Cargas, tax equity yields were trending down last year after several years of remaining stable. Do you think there is still downward pressure on yields?

MR. CARGAS: We are cautious about discussing pricing in public forums. Tax equity is unlike debt where you can look up accurate prices with a couple keystrokes.

There is also a more important point. Yields were a function for a long time of supply and demand. But as the deals themselves become more complicated, many more things bear on yield. You have projects with different cost mechanics, in different states, with different cash distributions and different credit buckets. There can be different offtake arrangements: corporate PPAs, PPAs with sponsor affiliates, puts, hedges, merchant tails. In the wind market, there can be various kinds of pay-go arrangements.

The point is that it has become much more difficult to generalize about yields. They are a function of a more sophisticated credit analysis based on numerous interactive risk and reward parameters.

MR. MARTIN: John Eber, let me ask the question differently. Falling yields are usually a sign of a buyer's market. Are you seeing more deals put out for bid among two or more tax equity investors?

MR. EBER: Yes. That was not uncommon before the financial crisis. It became less common after the financial crisis. Everything is settling down now. There are more investors. It is not unusual today to see sponsors ask for proposals from more than one tax equity investor.

I agree with what Jack said. Yields have trended down somewhat if you look at a mainstream wind deal with a 20-year power purchase agreement with a solid utility using well-known wind turbines in a stable part of the country.

However, as Jack pointed out, there is more variation today in deals. Only a small subset of the potential tax equity market may be interested in a deal with some merchant characteristics or unusual turbines. We are seeing a lot more corporate PPAs.

MR. MARTIN: How much of a yield spread is there among the principal asset classes: wind, utility-scale PV, residential solar, C&I rooftop?

MR. CARGAS: Offering generalized data points for each asset class is difficult for the reasons John and I just mentioned.

MR. MARTIN: John Eber, same answer?

MR. EBER: Pretty much. I think you can say utility-scale wind and utility-scale solar look alike from a return standpoint, but rooftop solar is a different market. / continued page 4

IN OTHER NEWS

US INDEPENDENT GENERATORS lost an effort before the US Supreme Court in late January to prevent demand response companies from bidding into power auctions on the same terms as independent generators offering to supply power.

The case is *FERC v. EPSA*.

The decision could lead to lower wholesale electricity prices in organized markets like PJM, the regional grid serving the mid-Atlantic states. It could make older, less-efficient power plants less likely to be dispatched. It could also allow businesses to earn money by better managing the electricity they use.

At issue were demand response companies, like EnerNOC, that collect promises from electricity consumers to cut consumption and then bid reductions in electricity usage into hourly auctions run by regional grid operators called RTOs.

Utilities that supply electricity to retail customers tell the RTO each hour how much electricity they will need. The RTO then takes bids from generators and other suppliers and dispatches the generators from least expensive to most expensive until it has all the electricity required that hour. The last megawatts purchased in the hour establish the price for all the electricity purchased that hour.

The Federal Energy Regulatory Commission issued an order that, as revised in 2011, requires RTOs to pay the same price for demand reductions as for additional electricity, with two exceptions. The RTO is not required to pay the same price if, under a "net benefits test," the utilities would end up not saving money by paying the marginal price to reduce load compared to paying for more electricity.

The other exception is the FERC order lets any state public utility commission prohibit consumers in its retail market from taking part in wholesale demand response programs.

The FERC order is Order No. 719.

To see the potential effect on wholesale power prices, if the last increment of electricity needed in an hour to get to / continued page 5

Cost of Capital

continued from page 3

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

MR. CARGAS: For wind, a third to two thirds of the capital stack is tax equity. For solar, the figure is probably a third to half.

MR. MARTIN: John Eber, are there any other noteworthy trends in the market as we enter 2016?

MR. EBER: The most noteworthy is the significant increase in the number of commercial PPAs for wind projects. The commercial and industrial solar market has always relied on them. The fact that they are showing up in wind is changing the dynamics of the marketplace.

It is great for wind. It is causing more megawatts to get built. However, we have to analyze a different kind of risk when underwriting deals. Bloomberg reported that more than 3,000 megawatts of commercial PPAs were signed in 2015.

MR. MARTIN: The commercial PPA market basically doubled last year from the year before. People expect further growth this year. Jack Cargas, is it harder to raise tax equity for a project with a commercial PPA than for one with a utility PPA?

MR. CARGAS: Yes, there is a difference. It has not been a standard offtake arrangement. We need to analyze the contract terms and the credit issues early in the process.

MR. MARTIN: Are there any other noteworthy trends as we enter 2016?

MR. CARGAS: We are keeping a close eye on what the states are doing on net metering. Nevada reduced the bill credits available to homeowners who send excess electricity from their rooftop solar systems back to the grid. Nevada homeowners are losing the financial incentive to install solar.

There are some pretty draconian predictions about what that does to the Nevada solar market, and other states are also evaluating changing their net metering rate structures.

It may be too early to call it a trend. It may never become a trend. However, if it were to become a trend, it could put a significant chill on the residential solar market in the affected states.

Bank Debt

MR. MARTIN: Let's move to bank debt. Tom Emmons, what was the North American project finance market in 2015 compared to 2014?

MR. EMMONS: Overall, 2015 was a very strong year, but there were winners and losers. The bank market was up 25% in dollar volume over 2014. Deal volume was $56 billion in 2015 compared to $45 billion in 2014. The increase is on top of a 65% increase in bank project finance lending from 2013 to 2014. The project finance bank market basically doubled in the last two years.

Those are the headline numbers, but what is going on within subsectors is more interesting.

In 2015, renewables were up 70% to $17 billion. Big growth occurred in both wind and solar, which was unlike 2014 when solar dominated. Both wind and solar were strong last year.

Oil and gas was flat at $20 billion, but within that number was a 50% jump in LNG loans to $17 billion in the first half of 2015 combined with a total collapse in upstream oil and gas from $4 billion in 2014 to almost nothing in 2015. Lending to finance gas-fired power projects was down 25% to $10 billion.

In summary, 2015 was the year that renewables moved into first place in power generation volume.

MR. MARTIN: How many active banks were there in 2015, and how many do you expect in 2016?

MR. EMMONS: There were 104 banks who were active in 2015, up about 10% from 2014 and up 50% from 2013.

But it is not the number of active banks that is telling; it is the volume of loans that the biggest players are making.

In 2015, 20 banks lent more than $1 billion each compared to 12 who lent more than $1 billion in 2014. The largest lender in 2015 committed almost $5 billion. The big players are doing more and more.

So as I anticipated a year ago, the depth of capacity in the bank market is coming from the bigger players doing more, and not from new banks coming into the market. Having said that, I expect in 2016 still more banks will enter the market.

MR. MARTIN: 2015 was an odd year. It got off to a slow start in terms of deals and picked up speed as the year went on. In late July to early August, share prices for TerraForm Power and NRG Yield and their affiliated sponsors crashed, and the market began withdrawing liquidity for buying operating assets. Until then, people had talked about a market awash in liquidity.

Did the market remain awash in liquidity to build new projects, and has lending recovered to buy operating assets?

MR. EMMONS: Banks always have an interest in new projects, but they also like operating assets, including portfolios, that can be seen as lower risk. My assessment of last year was that if there was a cooling of interest in operating assets, it was due to the sponsorship of those loans by yield cos and similar vehicles. The cooling off was not due to the asset class itself.

In terms of any recovery to buy operating assets, as I said, I think banks are always interested in operating assets, but they will remain selective and cautious as to the sponsorship for those operating asset loans until the yield co market stabilizes.

MR. MARTIN: So the market remained awash in liquidity all year, but some types of borrowers had a harder time as the year went on.

MR. EMMONS: That's right.

MR. MARTIN: What is the current spread above LIBOR for senior bank debt, and what does that translate into as a coupon rate?

MR. EMMONS: Of course, there is a range depending on a lot of factors, but I will try to generalize. For short-term construction debt, the spread is typically 1.5% to 1.75% over LIBOR. For term debt, maybe add a quarter percent with step ups over time. If that term debt is back leveraged, then add some more depending on the risks and structure of the back leverage.

As a coupon, you would add those spreads to a base rate of about 2.4%, which is the current 10-year swapped LIBOR rate. All in, long-term rates are in the low 4% range for term debt, which I think is very attractive.

MR. MARTIN: You are speaking about renewables primarily?

MR. EMMONS: Yes. I don't think the rates on loans to finance gas-fired power plants are all that far off, and gas-fired loans tend to have shorter tenors. Renewables, thanks to the long-dated PPAs, tend to be longer-term loans.

MR. MARTIN: The construction loan rate 1.5% to 1.75% above LIBOR. Add a quarter percent for term, and then you have a spread above that for back leverage. I think over the summer you said the spread for back leverage above term debt is 50 to 100 basis points.

MR. EMMONS: A big factor in the spread is deal size, because the number of back-leverage lenders is limited. Other facts are loan tenor, whether there is a hedge or a PPA, and then, of course, the size and shape of cash distributions to the sponsor over time.

The less lender-friendly these factors are, the shorter, pricier and tighter a back-leverage loan might be. For a back-leverage loan that is less lender friendly, there could be a premium of as much as 100 basis points.

MR. MARTIN: Back leverage tends to be found more commonly in the solar rooftop market. Is there is a difference in rates between residential solar and commercial and industrial solar?

MR. EMMONS: The more complex the deal, the fewer players there will be and the higher the premium for back leverage. For a straight, single project, utility-scale wind or solar deal, the spread will be smaller. For back leverage on a hedged wind deal, the spread will be larger, and the spread on a portfolio C&I solar deal will be larger still because of the complexity.

MR. MARTIN: What are current loan tenors? Start with senior

/ continued page 6

IN OTHER NEWS

what the utilities want to buy that hour is being offered by a generator at $40 a megawatt hour, and a demand response company is offering to reduce consumption by the same amount that hour for $35, then everyone that hour is paid $35. Justice Elena Kagan, writing for the Supreme Court, said FERC found that "heightened demand response participation will put 'downward pressure' on generators' own bids, encouraging power plants to offer their product at reduced prices lest they come away empty-handed from the bidding process." That also tends to reduce wholesale prices.

The Electric Power Supply Association argued that FERC is effectively setting retail electricity rates by ordering RTOs to pay the same prices to demand response companies and electricity suppliers. FERC has authority to regulate wholesale sales of electricity in interstate commerce. The states regulate retail sales and any wholesale sales that are wholly in-state and do not affect interstate commerce. The Supreme Court said the sales in this case are wholesale sales, even though the wholesale price has an effect on retail rates.

EPSA also complained that consumers who participate in demand-response programs receive a double benefit unless the retail rate they avoid paying is subtracted from the wholesale rate they are offered to cut consumption. The court said EPSA's approach is unadministrable, since retail rates vary by consumer type, time of day and geographic area. The court also said it had a hard time seeing the double benefit. An airline passenger who pays $400 for a ticket and is offered $300 to be bumped to a later flight is not paying $700 to fly, but the $400 he or she actually paid to fly, the court said.

The decision could open the door for FERC to require RTOs to open participation in hourly auctions to distributed generators and behind-the-meter energy storage facilities.

Although the court's decision involved a challenge to inclusion of demand response in RTO energy auctions, the court's holding applies equally to RTO capacity auctions. About 6.5%, or 11,000 megawatts, of the

/ continued page 7

Cost of Capital

continued from page 5

debt and then move to back leverage.

MR. EMMONS: Loan tenors, with a few exceptions, are staying under 10 years. Banks have higher capital and liquidity costs and can be more competitive for shorter tenors, so they try to keep tenors short. Mini-perms are a common technique to do that. Much of the demand in the renewable energy sector is for tax equity bridge loans, and they are typically under one year.

MR. MARTIN: What are the current debt-service-coverage ratios for wind, utility-scale solar, rooftop solar, natural gas projects?

MR. EMMONS: Generalizing again, wind is 1.45x, and solar is 1.35x. Those are P50 numbers.

MR. MARTIN: Is that the coverage ratio for utility-scale or rooftop solar?

MR. EMMONS: There could be a premium for rooftop, but not necessarily if there is good diversification of credit risks. It really depends on the individual case. Those are P50 numbers. For P99, the coverage ratio would be 1:0x or 1.1x for deals with power hedges. For natural gas, it could be as low as 1.4x for a project with a fully-contracted revenue stream, or higher if there is more revenue risk in the equation.

MR. MARTIN: What are current advance rates on construction loans?

MR. EMMONS: A lot of construction loans are tax equity bridge loans, and those attract a 95% or even a 100% advance rate. They typically have shortfall indemnities from the sponsor in case tax equity does not cover the full loan at the end of construction. Otherwise the advance rates can be as high as 85% to 90% for strong projects.

MR. MARTIN: A tax equity bridge loan is a construction loan that is expected to be repaid out of the capital a tax equity investor contributes upon coming into the deal.

There was downward pressure on interest rates last year. The number of banks increased, which meant more banks were chasing the same number of deals. The US central bank increased the overnight federal funds rate by a quarter percent in December. Many analysts expect as many as three or four rate increases this year.

To what extent are the rates you quote correlated to the federal funds rate? Do they move up at the same time?

MR. EMMONS: It depends on whether the loan is swapped or not. Short-term loans like construction loans typically are not swapped and so, therefore, they are pegged to LIBOR, typically three-month LIBOR, and the three-month LIBOR rate moved up in step with the increase in the federal funds rate.

So for unhedged short-term debt, there is a direct effect. Long-term loans typically are swapped against a Treasury rate commensurate with the average life of the deal. Those rates are not very well correlated to the federal funds rate and, in fact, some forecasts show the 10-year swapped LIBOR rate even coming down. The good news for term project financing is that the rate increases have had, and are expected to have, a very moderate effect on the effective cost of long-term borrowing.

MR. MARTIN: Have you been asked to lend to any merchant solar projects?

MR. EMMONS: If "merchant" means a project with no PPA or hedge, then the answer is very rarely. One example outside the United States is Chile, where several merchant solar deals have closed.

A few developers who are determined to keep some price upside potential do not want to hedge and may be able to borrow at lower advance rates and higher cost in deep power markets, but they are the exception.

MR. MARTIN: What would the lower advance rate be: 40%, 50%, higher?

MR. EMMONS: It would depend on electricity price forecasts and how believable the forecasts are. The advance rate would be set by discounting cash flow against future revenues, not just as a percentage of cost.

There were 104 active banks in the North American project finance market in 2015, up 10% from the year before.

Term Loan B

MR. MARTIN: Jean-Pierre Boudrias, what was the term loan B volume in the North American power sector in 2015, and how did that volume compare to 2014?

MR. BOUDRIAS: In 2015, there were 10 transactions for a total borrowing of $3.3 billion. That was down from 2014 when the deal volume was around $9 billion, and down from 2013 when the deal volume was around $11 billion.

The market tends to be a good place finance acquisitions. The market also has had in the past couple years a large number of refinancings. There were few of either type of transaction last year. There was also strong competition from banks to finance new projects. These factors help explain the drop in volume.

MR. MARTIN: That is almost a 50% drop from last year. It sounds like Tom Emmons is stealing your lunch.

MR. BOUDRIAS: The drop is due to a number of things. On the M&A side, acquirers have been using more corporate balance sheet finance, so that has removed some volume from the market. We saw the bulk of refinancings in 2013 and early 2014. In terms of new assets, the banks have financed the quasi-merchant gas plants to the tune of about $1.6 billion last year with only one deal in the term loan B market, which was a bank and term loan B deal for Panda Hummel, of which only $460 million was raised in the term loan B market.

MR. MARTIN: What percentage of the 2015 deals were merchant gas-fired power projects? You mentioned one.

MR. BOUDRIAS: It looks like approximately 60% of deals had a significant merchant component.

MR. MARTIN: They were all gas-fired power plants?

MR. BOUDRIAS: Yes.

MR. MARTIN: Were all of those projects in PJM or ERCOT? There was talk last year about merchant deals in New England.

MR. BOUDRIAS: The only new-build project that was financed in our market was in PJM. One project in New England was financed last year in the bank market.

MR. MARTIN: Has the market basically closed at this point to more PJM merchant gas deals? Are people feeling flush with that risk?

MR. BOUDRIAS: It requires a case-by-case determination. Obviously the investor community has a lot of exposure to certain sponsors. There may be more appetite for new sponsors at this point.

The broader theme across the market has been the continued retreat from energy stocks as oil prices fall and gas prices remain low. That has affected the fundamentals of / continued page 8

IN OTHER NEWS

total megawatts cleared in the latest PJM capacity auction were from demand response companies.

Next up before the Supreme Court is the flip side of the demand response case. The court will hear oral arguments on February 24 in two cases involving bidding programs that Maryland and New Jersey used to direct regulated utilities in those states to buy power from gas-fired independent generators under long-term contracts and pay prices that differed from the prices set in regional wholesale power auctions in PJM.

The cases will test whether the states crossed the line into regulating wholesale power sales. FERC is siding with the states in the two cases. (For earlier coverage, see the June 2014 *NewsWire* starting on page 1, the April 2014 *NewsWire* starting on page 15, and the December 2013 *NewsWire* starting on page 1.)

The cases may establish law on how far states can go in ordering regulated utilities to sign long-term power contracts with independent generators.

TREASURY CASH GRANT cases continue to advance in the courts.

A large wind developer lost an effort in December to compel the US Treasury to disclose information about the developer fees paid on wind farms.

Twenty-nine lawsuits have been filed against the US Treasury by companies that feel they were paid smaller grants than they are entitled.

The Treasury cash grant program was an economic stimulus measure in 2009 under section 1603 of the American Recovery and Reinvestment Tax Act to encourage construction of new renewable energy projects. Most larger US renewable energy projects are financed in the tax equity market. That market largely shut down in late 2008. Congress directed the Treasury in early 2009 to pay 30% of the cost of new renewable energy projects in cash in lieu of having developers claim tax credits. New wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects / continued page 9

Cost of Capital

continued from page 7

certain power markets, ERCOT in particular. If we look at a sample of deals in ERCOT, for instance, a year ago all these loans were quoted around 99% or 99¾% of face value. The same transactions today are quoted in the low 80s — for example, 82 — so that is an increase of 500 basis points in terms of yield to worse. Loan value is moving in the same direction in PJM, but not by as much. For example, the same portfolio around the same bid level of 99¾ in PJM is down to 95, which is about 75 basis points more in yield equivalent, which is a little bit more in line with the broader market.

Term loan B deal volume shrank in 2015 to $3.3 billion, down two thirds from 2013.

MR. MARTIN: Some listeners may not be familiar with a term loan B loan. What is it?

MR. BOUDRIAS: It is a loan documented largely like a bank loan, but that is placed with institutional lenders. The documents are more institutionally focused. By that, I mean that sponsors will generally have a greater degree of flexibility and freedom. Because it is harder to get a consent from investors than from a bank, the documents tend to be a little more sponsor-friendly by giving the sponsor more running room before amendments are required to the loan documents versus what you would see in the bank market.

MR. MARTIN: So it is basically the same bank debt that Tom Emmons is offering, but sold in then institutional market and perhaps a little more borrower-friendly.

MR. BOUDRIAS: The documents tend to be geared toward projects with higher risk: for example, for a merchant project or for holdco debt.

MR. MARTIN: Pricing a year ago for strong BB credits was around 350 basis points over LIBOR with a 1% LIBOR floor and 1% original issue discount, and single B credits were 500 basis points over LIBOR. Where do you see rates today?

MR. BOUDRIAS: We are probably 75 to 100 basis points higher than these levels. Some of it just reflects the broader malaise that we have seen across the leveraged finance markets overall. Some of it has been energy driven like the aversion to E&P companies that are directly affected by the downturn in oil and gas prices. It was widespread across most sectors of the market in 2015, so borrowing costs are higher than they were a year ago.

MR. MARTIN: So rates are continuing to go up. Are tenors and required coverage ratios the same as in the bank market?

MR. BOUDRIAS: Coverage has never been a good metric for term loan B debt because most term loan B's sweep excess cash to pay debt service. As a result, people will try to understand under a variety of scenarios how certain the loan is to be repaid by the end of the term. You would expect a base case to show the loan being paid off and, in the downside cases, 50% of the principal, or perhaps less, paid off. As far as tenor goes, the market has been pretty consistent. B loans tend to have a seven-year tenor. We do not expect that to change.

MR. MARTIN: How large a transaction must one have to make it worth the trouble to do a B loan?

MR. BOUDRIAS: Anything less than $250 million is probably not worth the trouble. Obviously some slightly smaller transactions were done last year. There were two transactions that were done in the low $200 million range, but it is difficult to justify the expenses for a loan of less than $250 million.

MR. MARTIN: How long should a transaction take?

MR. BOUDRIAS: Generally speaking, three months from beginning to end. Most of it goes into producing the material required to go through rating agencies. Once the loan is in the market, things move quickly. There is usually a two-week period to closing after the rating is received.

Project Bonds

MR. MARTIN: Jerry Hanrahan, the project bond market does not do well when the bank and term loan B markets are wide open and looking for product. We have heard the bank market is alive and well, and the term loan B was down last year.

There were no large syndicated project bond transactions in 2014. You and others did a few transactions on a direct, relationship basis. How many deals were there in 2015?

MR. HANRAHAN: There were probably a half a dozen or so deals last year in the investment-grade project bond market. There was one gas-fired deal early in the year that was well received, and the remaining deals were renewables, primarily solar, brought by corporate sponsors to the private placement or 144A market.

MR. MARTIN: How many active institutional investors were there?

MR. HANRAHAN: That is always difficult to gauge, but there is no shortage of liquidity. Everybody who can participate is participating.

There are probably somewhere around 25 institutional investors like ourselves who participate in these deals. The market is probably led by a group of eight or 10 of us who tend to be the anchor investors with larger teams and resources to bring to bear on a transaction.

MR. MARTIN: Last year at this time, you said there was one deal in the pipeline. How many are there in the pipeline today?

MR. HANRAHAN: Not many. It is hard to get visibility at this time of year as to what is coming, but there is one deal about which we are aware that went out as an RFP in the fourth quarter last year with the sponsor indicating that it prefers a bond structure. I expect that deal, if it ends up as a bond structure, to come to market in the first quarter this year.

Beyond that, we do not have a lot of visibility. Given what has just been said about the bank and term loan B markets, we will probably see a similar year this year to what we did last year.

MR. MARTIN: Project bonds are fixed-rate debt, and they tend to be longer term than bank loans and term loan B debt. Both of those products are floating rate debt. Project bonds need a spark, like a fear of rising interest rates, before that market gets traction. Are we at such a point today?

MR. HANRAHAN: It is possible. It all depends on one's view of inflation and how much interest rates might increase. The advantages that we can offer are the longer tenor and the fixed-rate nature, and there tend to be little or no fees associated with bonds. So those are the pluses that we can / continued page 10

IN OTHER NEWS

qualified for grants if put in service during the period 2009 through 2011 or if they were under construction by December 2011 and put in service before the end of 2012. Solar and fuel cell projects continue to qualify for grants if put in service by the end of this year. However, they had to be under construction by December 2011.

The wind developer says it was shortchanged by $9.2 million on the grant paid on one wind farm and by $12.7 million on another. Both projects are in Illinois. One of the issues in dispute is how much of a $50 million developer fee the project company paid to its parent company in one of the projects, and a $60 million developer fee in the other, can be included in the project cost for calculating grants on the projects.

The developer, Invenergy, asked the US Court of Federal Claims, where the cases are pending, to compel the government to tell it about the grants paid on 108 other wind farms, including the developer fees paid and the extent to which the Treasury allowed them to be included in basis.

The judge ruled on December 21 that "how the [government] may have treated other taxpayers has generally been considered irrelevant in making that determination," quoting a US Tax Court decision in a tax case. The Treasury argued that the raw numbers are not useful without a lot of other analysis about the particular facts of the cases. Even if the information is of tangential relevance, the judge said, it is too burdensome a request to force the Treasury to spend time gathering it.

Curiously, the judge failed to mention that her court has held in the past that the US tax authorities cannot discriminate against taxpayers who are similarly situated. For example, the Claims Court said in a well-known case in the 1960's that the Internal Revenue Service could not rule privately that a 10% excise tax on "business machines" did not apply to computers sold by Sperry-Rand while making IBM pay the tax on its computer sales. Remington Rand (which was later acquired by Sperry Corporation) obtained a private ruling that its machines were not subject to the tax. IBM sought a / continued page 11

Cost of Capital

continued from page 9

use to attract borrowers.

If we are in a rising rate environment, then bonds will look more attractive. We do well then. We also do well when there is some dislocation in the market that people can arbitrage against; for example, if there is a larger spread than normal between the LIBOR swap spreads used to price bank debt and Treasuries.

MR. MARTIN: What is the current spread above treasuries, and what does that translate into as a coupon rate?

MR. HANRAHAN: It is a range like everyone else has answered. A typical investment-grade project could expect to pay a rate in the mid-200 basis point level above average life Treasuries, plus or minus depending upon the particular features and quality of the deal. It could be anywhere from the low 200s to high 200s or even 300 basis points above average-life Treasuries. We tend to do longer-term deals, so we are usually pricing off something in the area of a 10-year Treasury, which today is around 215 basis points, so you end up with coupons in the low-to-mid 4%, maybe 4.5%, range.

MR. MARTIN: That is not much different than the current rate on bank debt.

MR. HANRAHAN: Not much.

MR. MARTIN: Shouldn't this market start to get traction when people think we are at the bottom of the interest rate cycle; it is a chance to lock in an historically low rate.

MR. HANRAHAN: Right.

MR. MARTIN: Another key difference between project bonds and term loan B debt is project bonds generally have the same tenor as the power purchase agreement, correct?

MR. HANRAHAN: Yes.

MR. MARTIN: There is no upfront fee like these other two products because the economics are fully baked into the spread. When are ratings required?

MR. HANRAHAN: Ratings are generally not required, at least by us and the other large insurance companies. Sponsors tend to get ratings if they are worried about execution or they want to attract some of the smaller players who are more comfortable in rated deals, or if they opt to go the 144A route, in which case ratings would be required.

We don't require them ourselves, but we will structure a deal to a BBB investment-grade rating internally.

MR. MARTIN: Of course, the big difference between bank and term loan B debt and project bonds is project bonds require a make-whole payment if the bonds are repaid ahead of schedule. How is such a payment calculated?

MR. HANRAHAN: It is calculated off a spread to Treasuries when the bond is repaid. It is less likely in a rising rate environment that there will be a make-whole payment if rates are higher on the early payment date than at time of original issuance. You probably have no incentive to refinance in such a case in any event. You locked in a lower rate than you can get by refinancing.

MR. MARTIN: How long does it take to do a project bond deal?

MR. HANRAHAN: If the deal comes to us in the syndicated private placement market, then you are usually talking two to four weeks. A direct-placement deal requires a couple months to complete the due diligence and documentation.

MR. MARTIN: How large a transaction does one need to make it worthwhile?

MR. HANRAHAN: For the direct placement deals that we do, the transaction size is usually $30 to $50 million. A syndicated deal should be $100 million.

How to Lose a Banker in 10 Minutes

by John Schuster with 32 Advisors, in Washington

My experience as a lender in the project and structured finance space was that fewer than 10% of all projects presented for finance were sufficiently developed and ready for prime time consideration when they were brought to the bank's attention.

I usually needed only about 10 minutes to review and kick back the deal to the project developer for additional work that may have been tantamount to rejection. This often left me frustrated, as project developer teams were for the most part earnest, hard-working, and well-intentioned.

More often than not, the borrower was a renewable energy developer, a sector attracting project teams that are relatively inexperienced in project finance. Borrowers were attempting to seize opportunities to develop clean energy projects in emerging markets. [*Editor's note: John Schuster was head of the structured finance division of the US Export-Import Bank before joining 32 Advisors in 2014.*] While this left me disheartened, I knew that misleading developers would only hurt them in the long run. They would just keep making the same mistakes.

This repeated saga inspired me to deliver a speech at a renewable energy financing conference in Long Beach, California entitled "How to Lose a Banker in Ten Minutes." I listed the key *faux pas* committed time and time again and scripted a "what-not-to-do" speech, inspired by the Kate Hudson and Matthew McConaughey movie "How To Lose a Guy in Ten Days." Kate Hudson's character — Andie — uses Matthew's character — Ben — as a guinea pig in an article about all the things women do to lose guys. Andie's intentional *faux pas* included dragging Ben to a Celine Dion concert the night of a big Knicks game and making a visible and clingy appearance on boys' poker night.

The speech was a big success, eliciting lots of chatter, laughs and agreement and I thought learning on what not do in presenting an infrastructure deal to a bank.

That was until, when at the evening cocktail reception, someone approached me to congratulate me on the speech and introduce a project. Within one minute — not even 10 minutes — he did all the things that I had just told the group not to do. So there may have been entertainment, but not as much learning as I thought. Below is my attempt — again — to teach professionals operating in the global project finance arena.

High-Level Contacts

My first suggestion is lead with your high-level contacts.

Demonstrate how these relationships are the key to your success. I cannot count how many times I heard about high-level contacts and relationships. Typically the contact was with the a deputy minister or minister of a key department. Sometimes it was with the prime minister or president of a country. The higher the level, the better, most thought.

Bankers think something else. Deals that arise because of key political relationships are either not real or are highly vulnerable, and are around only long enough for the next developer to come around and request a meeting. At worst, the high-level contact can conjure up concerns of bribery or corruption. Serious developers and borrowers have contracts, sales track records, or both. Anyone touting a high-level political contact as an opener is labeled as not serious and lacking substance. I suggest an MOU signed by the king if there is one.

If the banker is still in the room after that, tout the project's high rate of return.

Most people cannot understand why an advertised rate of return is bad, and that is why this mistake is so common. Why are high returns bad? First, bankers do not really care what the rate of return is. Banks care about "debt / *continued page 12*

IN OTHER NEWS

similar ruling for its competing product. The IRS did not respond to IBM's ruling request for more than two years, after which it wrote to IBM that the equipment was subject to the excise tax on a retroactive basis. The IRS notified Remington Rand about a week later that it intended to revoke its ruling, but only on a prospective basis. IBM had been paying taxes during this entire period.

The Claims Court held that the IRS abused its discretion in ruling that IBM's computers were taxable retroactively and that Remington Rand's were taxable only prospectively. It said that IBM was entitled to recover the excise taxes it paid during the period in which Remington Rand was exempted from tax.

The decision has been cited favorably in several other Claims Court opinions.

The Invenergy lawsuits are *California Ridge Wind Energy LLC v. US* and *Bishop Hill Energy LLC v. US*.

Of the 29 lawsuits filed against the Treasury, two have been decided. The government won one and lost one. (For earlier coverage, see the February 2015 *NewsWire* starting on page 7 and the May 2015 *NewsWire* starting on page 5.) Both decisions are now before US appeals courts.

Seven other cases have been dismissed, either because the government countersued and the taxpayer thought better of its claim or because a settlement was reached.

A settlement appears to have been reached in potentially the most interesting case that raises the issue whether part of what is paid for an operating wind farm that comes with a power purchase agreement must be allocated to the PPA. The settlement, if there was one, has not been made public.

Three of the 29 lawsuits were filed in federal district courts. At least one involves a whistleblower claim.

Seven were filed by tax equity investors in the various Alta wind farms in California.

Other interesting issues raised by the pending suits are whether / *continued page 13*

How to Lose

continued from page 11

coverage" — how much cash margin or coverage there is to pay debt, or about "debt leverage" — the ratio of debt and equity in a deal. Terms with the word "debt" in them — get it? Return is an equity concern; better projects deliver more return to equity holders. Debt just gets paid, hopefully on schedule. Banks are also unimpressed with high projected returns because those returns are just projections loaded with assumptions. The higher the return, the less credible the deal. Want to be certain to lose your banker? I suggest a 40% IRR.

There are at least seven ways to make a banker reject a project quickly.

Touting high returns only raises flags, especially to lenders of last resort such as the International Finance Corporation or US Export-Import Bank. If the developer is making so much money, then why is it asking such an agency for financing? What's wrong? Or, if there is so much money to be made, maybe the bank should sweep it, meaning have some debt prepaid so that equity is not returned before then debt is.

For that reason, sophisticated large company sponsors of projects go to great lengths to conceal returns. While transparency is best, I would give brownie points to developers who at least tried to keep profits under wraps.

Hotmail Address

Use a "hotmail" web address.

An AOL account or a gmail address will do, but most of the really questionable deals all seemed to use hotmail addresses. Small parties just starting out or just forming a special-vehicle company may not have a website or a proper email address at first, but it is not really that hard to get a domain name. Somehow, parties came to the bank seeking serious finance without a serious email address. This put an immediate black mark on the borrower. One business development specialist would almost completely discount a deal's probability of success just for the lack of a professional email address. Once a borrower has a real email address, and a business card and company materials to confirm, it is a whole new world. Want to lose the banker fast — hotmail it is.

Banker still awake? Then take up valuable time trying to sell the project technology to banker.

How can it possibly be bad to sell the technology to the banker or talk up the product? Aren't the project's technology and the products it makes what makes money to pay back debt? They are, but that does not matter, because — here's the big mystery — the banker is not the one buying the products! Even if the banker is totally wowed by the technology, it does not matter. When looking at large infrastructure or other projects, banks want to see long-term contracts with strong terms to sell products to credit-worthy buyers, or at least a deep market with a strong track record where competing projects have higher costs.

If you really want to lose your banker, then go on and on about what a revolutionary breakthrough the project represents. That way, the banker may nod off or, better yet, become worried that he is being asked to take new technology risk, i.e., the risk of developing and commercializing a brand new technology, a risk that most banks will not assume. Really want to walk out empty-handed? I suggest cold fusion technology.

If there is any one left in the room, assume success.

There are lots of easily available competitive advantages you can assume, such as access to a fuel source or a short-term market failure that will make a new project a big success. Developers of biomass projects using agricultural products or waste for fuel or waste-to-energy deals using municipal waste to generate power or produce fuel seem to specialize in this tactic. Bankers would impatiently tap fingers on the table when developers got going. The key to success for these projects was always their ready access to agricultural or municipal waste within a specified radius of a project. To make their point, developers would draw circles around the project and identify how

chadbourne

much agricultural or municipal waste was produced and discarded within each circle. Developers would claim that there was so much cheap fuel available within the project area that, even without supply contracts, the project will earn large profits from a consistent supply stream.

Assuming your own success is a great tactic for losing a banker because challenging assumptions only takes a few minutes. What could go wrong with easy access to free fuel within a few miles of a project? To start with, agency and other lenders typically give credit to what is contractually committed and sure to be available.

Second, there are many things that can and will go wrong with a supply of agricultural and municipal waste. Bad weather can intervene, or there can be problems with collection and processing mechanisms for waste. Digging deeper, relying on a large number of contracts from farmers or municipalities means lots of short-term agreements with parties with uncertain credit.

Ultimately, the whole premise for assuming one's own success is just wrong. If there is a magic bullet such as a reliable stream of waste for power, then the nasty old free market always catches up with you. Other projects pop up and increase demand for the same fuel, thus driving up costs. Remember when corn prices rose to such high levels? The culprit was a large number of ethanol projects that used corn; most of those projects went bust when corn feedstock prices rose.

There is simply no free lunch. But, to lose the banker, invalidate those antiquated economic principles and assume a really great magic bullet that allows you to print money.

If there is still one person in the room, highlight a great unmet need as a selling point.

There are, quite sadly, millions of people in Africa and other parts of the world who lack access to electricity. There is a dearth of refining capacity throughout many parts of Latin America and Asia. In spite of economic growth, many places throughout the developing world lack access to basic products. A banker will see this lack of development as a sign of credit weakness, before believing economic growth signals credit strength. Power in Africa is scarce mostly because there is too little income to pay for it, or because regulatory and political systems are too weak or corrupt so that there is no money to pay for power. Bankers first look for the money that will ultimately repay the debt; they are funny that way.

The losing strategy? Tout how little money there is for your project or any other project.

/ continued page 14

IN OTHER NEWS

part of the purchase price in a sale-leaseback must be allocated to intangibles like going concern value, what are the fair market values of various wind farms and rooftop solar systems financed in the tax equity market, to what extent the government can impose percentage limits on markups from construction cost in arriving at market value, whether part of the cost of a power plant that makes steam as an intermediate step to generating electricity, and then gets double duty from the steam by diverting part of it to an industrial use before sending to back to a condenser and then to the boiler as water to restart the cycle, can be denied a grant on a part of the project cost that the Treasury says represents the steam usage, and whether equipment that cleans gas before it is used in a fuel cell qualifies as part of the fuel cell on which the grant is paid.

The oldest case has been pending since February 2012.

The most recent lawsuit is one filed in December 2015 by Nippon Paper Industries USA Co., Ltd. The company says that Treasury reduced a grant it was paid on a 20-megawatt power plant that it completed at a paper mill in Port Angeles, Washington in 2013. The Treasury allowed a grant on only 82.8% of the project cost after allocating part of the cost to steam put to industrial use. The lawsuit says that the company is aware of seven other biomass power plants that received full grants on similar facts: Seneca Sustainable Energy, LLC in Oregon, Roseburg Forest Products Co. in California, Simpson Tacoma Kraft Co., LLC in Washington, WE Partners I, LLC in North Carolina, Cosmo Specialty Fibers in Washington, Verso Bucksport, LLC in Maine and Shasta Renewable Resources, LLC in California.

The next case set for trial is LCM Energy Solutions. Arguments will be heard on April 26.

LCM filed suit in May 2012 asking the Treasury for the difference between the $482,504 it was paid and the $889,638 for which it originally applied on 18 solar rooftop systems. Treasury valued the 18 systems at $5.70 a watt for purposes of paying grants. The company wanted roughly $10.50 a watt.

/ continued page 15

How to Lose

continued from page 13

Go Really Big or Small

One last pointer is go big or go home — and you will really go home.

You can also go small and go home.

Make the project really big with layers of infrastructure so that it is complicated with huge loan exposures. My favorite was a wind farm that was placed on ships and then connected to a new electricity grid that powered a refinery and petrochemical project. The project cost billions of dollars. The presentation had the predictable effect of scaring several banks.

Banks prefer reasonable exposures that can be managed within the boundaries of the sources of credit, but if you want to clear the room, a complex, multi-billion dollar deal is better. A very small project is better than an enormous project, but can also create problems, especially for project finance. It can cost as much, or more, money to project finance a small deal as a big one. Banks would prefer that smaller deals have bank guarantees or other structures, but to lose the banker's attention, insist that the small deal be financed through project finance.

Next Steps? These are the basics and most apply to new developers, but a surprisingly large group of experienced borrowers will continue to make these mistakes. If you think you or your deal is different, think again. Once you have really learned these lessons, there are still more subtle ways to lose a banker. In doubt — call us — we can help. ◎

Another Race to Start Construction: Practical Advice

by Keith Martin, in Washington

The decision by Congress to extend expiring tax credits for renewable energy through 2019 for wind and 2021 for solar — with phase outs — could reduce the volume of new wind and solar construction in 2016, but bring lots of additional investment ultimately into the sector.

Congress may revisit whether to allow more time for fuel cell and combined heat and power projects.

Many renewable energy companies may turn to raising new capital to dive back into project development. Development pipelines had thinned as it looked like the tax credits were running out.

The key to qualifying for tax credits is to start construction of new projects by the new deadline and then be able to show continuous work on the projects after the construction-start deadline.

The IRS has not been making developers who finish projects within two years after the deadline prove continuous work. It hopes to issue a notice in March to explain how it will apply this policy now that a larger range of projects qualify potentially for tax credits if they are under construction by future deadlines and the amount of tax credits for which a project qualifies varies depending on when construction starts.

Many useful lessons can be drawn from the experience of wind companies with construction-start deadlines in 2013 and 2014.

Tax Credit Extensions

Tax credits for renewable energy projects were extended in December as follows.

Wind developers will have through December 2016 to start construction of new wind farms to qualify for 10 years of production tax credits at the full level. Production tax credits were $23 a megawatt hour for wind electricity in 2015. The credits are adjusted each year for inflation. The 2016 figure will not be announced until April. The tax credits run for 10 years after a project is first put in service.

Projects that start construction in 2017, 2018 or 2019 will qualify for 10 years of tax credits at reduced levels. The levels are 80% for projects starting construction in 2017, 60% in 2018 and 40% in 2019.

Developers will have the option to claim a 30% investment tax credit instead of PTCs during the same period and with the same phase down. Thus, for example, a developer who starts construction of a wind farm in 2018 could claim an 18% investment tax credit (30% x 60%).

Solar projects that are under construction by December 2019 will qualify for a 30% investment tax credit. The credit will fall to 26% for projects starting construction in 2020 and 22% for projects starting construction in 2021. The full investment tax credit is claimed in the year the project is put in service.

Projects that are under construction before these deadlines must be placed in service by December 2023 to qualify.

The investment credit will revert to its permanent 10% level after that. Thus, any project that is not under construction in time would still qualify for a 10% investment tax credit.

The tax extenders bill also extended the residential solar credit for homeowners who choose to buy solar rooftop systems or solar hot water heaters rather than enter into solar leases or power contracts with solar companies. They could claim a 30% tax credit on such equipment put in service through 2019. The credit drops to 26% in 2020 and 22% in 2021. It disappears after that.

Moving to other forms of renewable energy, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects will have until December 2016 to start construction to qualify for production tax credits. Developers of such projects will retain the option to claim a 30% investment tax credit instead of PTCs during the same period. Such projects were not given the same additional phase down as wind and solar.

The current 30% investment tax credit for fuel cells was not extended. Fuel cells must be in service by December 2016 to qualify under existing law.

Nancy Pelosi, the House Democratic leader, said as the tax extenders bill passed in December that she had a commitment from House Republican leaders to revisit in 2016 whether to extend expiring tax credits for fuel cells and CHP projects. She said tax credits for these types of equipment were not extended due to an oversight. Kevin Brady, the House tax committee chairman, said that his committee will take a look in 2016 at whether such tax credits should be extended. "The fuel cell and other breaks don't expire until next year, and tax writers will likely work on the issue some time in 2016," he said.

Accelerated Depreciation

Congress extended a 50% "depreciation bonus" that expired at the end of 2014 retroactively to the start of 2015. Companies that put new equipment in service in 2015, 2016 or 2017 can deduct 50% of the tax basis in the equipment immediately and the other 50% using the normal depreciation table. New equipment put in service in 2018 will qualify for a 40% bonus. Equipment put in service in 2019 will qualify for a 30% bonus.

Assets, like transmission lines and gas-fired power plants that have longer depreciable lives, could qualify for the 50%, 40% or 30% bonus for an extra year. Thus, for example, a 50% bonus could still be claimed on the cost of transmission assets completed in 2018.

The bonus on longer-lived assets can only be claimed on the portion of the project cost incurred through 2019. Thus, a transmission line or gas-fired power plant / continued page 16

IN OTHER NEWS

The government later filed a counterclaim against LCM accusing the company of fraud and asking not only for denial of the company's claim for more money, but also for civil penalties of up to $220,000 plus treble damages of three times the amount the company was already paid, or $1.4 million. The government found the legal arrangements around the 18 systems were a mess when digging more carefully into the facts after the company filed suit. (For more details, see the April 2014 *NewsWire* starting on page 27.)

The next scheduled trial after LCM will start June 21 in a case involving GUSC Energy, Inc. That case involves another biomass power plant on which the Treasury reduced the grant after allocating part of the project cost to steam usage. The Treasury also excluded from the grant calculation costs related to site cleanup, landscaping, ornamental iron work and paving. (For more details, see the February 2015 *NewsWire* starting on page 7.)

MEXICAN renewable electricity targets have increased.

A new law in December sets renewable electricity targets at 25% by 2018, 30% by 2021 and 35% by 2025. Mexican installed capacity was 25.3% renewable energy in 2015, but renewables accounted for only 18.2% of output, according to Javier Felix with Chadbourne in Mexico City.

H-S-R THRESHOLDS for advising the US government of planned acquisitions have been updated. The new thresholds were announced in late January and apply to transactions that close on or after February 25, 2016.

The Hart-Scott-Rodino Act is an antitrust statute that requires parties to an acquisition to make a detailed filing with the Federal Trade Commission and Department of Justice, and to give those agencies time, usually 30 days, to review the proposed transaction before closing. According to Robert Schwinger and Benjamin Bleiberg with Chadbourne in New York, transactions now valued at more than $78.2 million will trigger H-S-R reporting / continued page 19

Starting Construction

continued from page 15

completed in 2020 would qualify for a 30% bonus, but only on the basis built up in the asset through the end of 2019. Longer-lived assets put in service before 2020 would get whatever bonus applies to the full project cost.

The depreciation bonus is an acceleration of depreciation that would otherwise be claimed on a project. Thus, for example, wind farms in the United States are largely depreciated over five years. With a bonus, 50% of the project cost is taken as a depreciation deduction in year 1, and the remaining 50% of project cost is depreciated over five years, including partly in year 1.

Projects on Indian reservations can be depreciated more rapidly than projects in other parts of the United States. For example, a wind farm or solar project on an Indian reservation can be depreciated over three years rather than five years. This will remain true of any such projects that are completed by December 2016. The provision had expired at the end of 2014. The tax extenders bill extended it retroactively.

Starting Construction

Solar companies will have to focus on what it means for a project to be under construction. Many solar companies had experience with construction-start rules under the Treasury cash grant program, but the tax rules are different.

Developers of wind, geothermal, biomass and other projects that qualify for production tax credits have had to live with the IRS construction-start rules since 2013.

There are two ways to start construction.

One is by "incurring" at least 5% of the final project cost. Costs are not incurred merely by spending money. The developer must either take delivery of equipment before the construction-start deadline or else pay before the deadline and take delivery within 3 1/2 months after payment. Delivery can be at the factory. The IRS modified the 5% threshold in August 2014 to say that a developer who incurs at least 3% of the final project cost can claim tax credits on a fraction of the electricity output or project cost. At 3%, the project would qualify for 60% of the normal tax credits. At 4%, it would qualify for 80%.

The other way to start construction is to commence "physical work of a significant nature" at the project site or at a factory on equipment for the project. The IRS has interpreted the physical work test in a liberal manner so that not much must be done before the deadline. However, many tax equity investors have not been as keen to finance projects that rely on physical work.

It is not enough merely to have started construction in time to qualify for tax credits. There must also be continuous work on the project after the construction-start deadline. The IRS has not been making developers prove that there was continuous work on any project that is completed within two years after the deadline.

IRS and Treasury officials are talking about issuing a new notice explaining how they will apply this presumption now that the tax credits step down in amount over time. They are debating whether to spare companies from having to prove continuous work if a project is put in service within two years after the last construction-start deadline for any credit or to have separate two-year periods for each step down in the credits. Some counsel have suggested that, under this "vintaging" approach, a developer would also have to prove that construction of the project did not start too soon. It is unclear why this would be the case. The government hopes to issue a new notice on the two-year presumption in March.

Another issue under discussion is whether to have separate presumptions of varying lengths for different types of projects. For example, geothermal and offshore wind projects take more time to build than onshore wind farms. However, the IRS may decide this is more trouble than it is worth.

Another issue with which the government is wrestling is how the new rules apply to solar. It is not clear how they will work for rooftop solar installations. The US Treasury let rooftop solar companies stockpile solar panels and inverters and then claim grants on rooftop solar systems

A number of lessons can be drawn from the experience with recent construction-start deadlines.

that use enough of this equipment to amount to more than 5% of the system cost. There was no continuous work requirement under the grant program.

It may also be harder for solar companies to start construction under the physical work test. Physical work at the factory on equipment for a project counts, but not if the factory starts manufacturing the equipment before there is a binding purchase order in place, and the equipment cannot be of a type that is kept in inventory. Solar panels and inverters are usually kept in inventory, unlike wind turbines that, even though the manufacturer has standard models, are not manufactured until a binding order is received.

The IRS is not expected to address the solar issues until later in the year.

The IRS takes the position currently that if one turbine at a 50-turbine wind farm slips past the two-year window, then the developer must prove continuous work on the entire project. The IRS gives the developer the benefit of treating the entire project as under construction in time based on incurring a fraction of the cost or starting physical work on a small piece of the project. Therefore, it also treats the project as a single project for assessing at the back end whether the project made it into service in time to benefit from the continuous-work presumption.

Opportunities

The tax credit extensions are expected to take the pressure off developers and the tax equity market to close as many financings in 2016.

Larger wind developers who can afford it are expected to negotiate more contracts this year to buy "PTC components" on which they need to take delivery this year or in the first three and a half months of 2017. Developers had been stockpiling nacelles, blades and tower segments for use after the construction-start deadline in future projects.

Smaller developers who do not have the money to pay for equipment orders this year will end up late in the year trying to mobilize excavation or road contractors to dig turbine foundations or put in roads on project sites before year end. Weather could be a factor at some sites.

The extension may put developers who relied on the physical work test to start construction of projects before 2014 in a stronger position to persuade tax equity investors and lenders that the physical work is significant if more work was done on the project in 2015 or can be done before year end 2016.

Some larger developers stockpiled / continued page 18

IN OTHER NEWS

requirements. There is no H-S-R reporting for any transaction valued at $78.2 million or less, regardless of the percentage of assets or voting securities to be acquired.

Under a size-of-person test, when the value of a proposed transaction exceeds $78.2 million, but is less than $312.6 million, then the transaction must be reported if one party to the transaction has total assets or net sales of $156.3 million or more and the other party has total assets or net sales of $15.6 million or more.

All transactions valued at more than $312.6 million must be reported.

COMPANIES OPERATING IN MULTIPLE US STATES lost a bid to get back income taxes paid in California.

Each US state taxes income earned in the state. Because the states have different approaches to determining how much income a large company operating nationally earned in each, there is the potential for double taxation. A House subcommittee recommended in 1965 that Congress impose a uniform apportionment regime on the states. State tax administrators from nine states drafted a multistate tax compact in 1967 in an effort to avoid federal action. The multistate compact adopts a three-factor formula in which a company apportions income to the state based on the share of the company's total property, payroll and sales in the state. The three factors are given equal weight.

California adopted the multistate compact in 1974. However, in 1993, it changed its law to require double weighting be given to the sales factor.

Gillette and five other companies sued the state for $34.6 million in refunds in 2010 arguing that they are entitled by law to use the formula in the multistate tax compact.

The California Supreme Court disagreed in a decision on December 31.

The state enacted a bill in July 2012, shortly before a decision by a state appeals court in favor of the companies, / continued page 19

Starting Construction

continued from page 17

equipment in 2013 and 2014 that could be used in future projects. As long as the equipment actually used amounts to at least 5% of the final project cost and there was continuous work on the project after the construction start deadline, then the project qualifies for tax credits, unless the IRS decides that any "vintaging" concept for proving continuous work also requires a developer to prove construction of the project did not start too soon.

The IRS has been concerned about trafficking in stockpiled equipment. Under IRS rules, Developer A holding such equipment could transfer it to Developer B for use by Developer B as a basis for claiming tax credits, but only if Developer A contributes the equipment for more than a 20% interest in Developer B's project. The extension in the construction start deadline opens a window for developers holding 2013 and 2014 equipment to sell it to other developers who can count the costs as incurred 2016 costs in their own right.

Lessons

A number of lessons should be taken away from the push by wind developers to start construction in 2013 and 2014.

If at all possible, start construction by incurring costs rather than relying on physical work.

Developers with projects that are not completed until after whatever two-year presumption the IRS establishes will have to prove continuous work to claim tax credits. This is easier to do for projects that rely on the 5% test than for projects that rely on physical work.

A developer must show "continuous efforts" on any project that was under construction based on incurred costs.

He or she must show "continuous construction" for any project that was under construction based on physical work.

"Continuous efforts" contemplate that the project can still be merely under development; thus, development-type tasks like working to secure permits, a project site and an interconnection agreement and negotiating with vendors, financiers and construction contractors count as continuous efforts.

"Continuous construction" contemplates that a project is truly under construction. This may be hard to do for a wind farm on land with a normal construction period of six to eight months if the project is not completed until after the two-year window.

Anyone relying on continuous efforts should document the effort. The development team should come in every Monday morning and ask what it can do that week to advance the project, work at it, and keep detailed logs showing what was done from one day to the next on the project. It does not matter if the project is expected to be completed in time to benefit from the presumption that there was continuous work. The documentation is an insurance policy in the event the construction schedule slips.

If physical work is the only option, then it is better to dig turbine foundations or put in turbine string roads than to do minimal work on transformers or other equipment at a factory. If at all possible, dig at least 10% of the turbine foundations. Finish more than a mile of road to the permanent surface. If possible, clear or plot out the remaining roads. Access roads that allow entry on to the project site from the public highway do not count; what counts are string roads that connect one turbine to the next. The IRS declined at the request of wind developers to draw a bright line around what qualifies as "significant" physical work, but it made clear in an August 2014 notice that not much had to be done. However, the tax equity market has been less keen to finance projects that rely on minimal physical work. Tax equity investors have more projects from which to choose than there is available capacity. They will choose the ones that present the fewest tax risks; therefore, the stronger the physical work facts, the better.

The developer must have a binding contract in place with the construction contractor before physical work starts for the contractor to do the work and for the developer to pay for it. The contract does not have to be for the full job: for example, it can be for excavating just a fraction of the turbine foundations.

It is not a good idea for the developer to retain a right to terminate the contract for convenience. That may turn the contract into merely an option to have the work done, even if the developer is required to pay for the work that has been completed before cancellation. The safest course is to require payment of at least 5% of the remaining contract price in damages.

Anyone relying on physical work should document the work that was done before year end. Take photos of the site. Have an independent observer visit the site at year end and attest to what he or she saw.

The 3 1/2-month rule — where the developer pays before the construction-start deadline for equipment that will be delivered within 3 1/2 months after payment — is a "method of accounting." Not every company can use it. A developer should confirm with its accountant that it can use this approach. Forming a partnership may help, as the partnership is allowed to choose a new method of accounting without having to get IRS permission to change its accounting method.

It does not work to give a turbine vendor a recourse note by the construction-start deadline for equipment to be delivered within 3 1/2 months after payment. The IRS requires "payment" before the deadline if equipment is to be delivered early the following year. It defines "payment" as "cash or cash equivalent." What the IRS had in mind by a cash equivalent is a debt instrument for which there is an active market: for example, corporate debt traded on an exchange. Case law suggests a note can be a cash equivalent, but only if four things are true about it. The note must bear an arm's-length rate of interest, it must be freely transferable, it must be a kind for which there is an active market so that it is easily convertible into cash, and any discount at which it trades should only reflect changes in the cost of money rather than the likelihood of payment by the obligor.

When taking delivery at the factory, make sure that both title and risk of loss transfer. The developer should pay storage fees and buy casualty insurance while the equipment is being stored. Have a delivery certificate showing someone inspected the equipment on behalf of the developer. If the vendor charged for future transportation to the project site as part of the equipment price, back it out of the costs considered incurred before the construction-start deadline. Transportation is a service, and the cost of services is not incurred until the services are fully performed. The same principle applies to a prepaid storage fee that is built into the price of the equipment. Make sure any sales taxes that must be paid after a real sale and delivery are paid. Segregate the equipment from other equipment belonging to the vendor, especially if the vendor is pulling the equipment out of inventory, and tag it as property of the developer. If the equipment is defective, it is better for the vendor to repair it under warranties rather than to reject the equipment so that the cost of the equipment continues to count as fully incurred before the deadline.

IN OTHER NEWS

withdrawing from the multistate compact and barring refund claims unless a company elected use of the apportionment formula in the multistate compact when it filed its tax return.

The California Supreme Court said the state remains free to change its tax law, including overriding the formula in the multistate compact. The companies argued that the compact is a binding reciprocal agreement among states that the California legislature cannot change unilaterally. The court disagreed. It said adoption of the compact made it state law, and the state remains free to change its law. The companies also argued that it is not clear the state legislature intended to eliminate the ability of companies to elect the compact formula. The court disagreed.

The companies plan to appeal to the US Supreme Court. The case is *Gillette Co. v. Franchise Tax Board*. California could be exposed to about $750 million in total refund claims if it loses.

Multistate compact cases are also before the courts in at least four other states: Oregon, Minnesota, Michigan and Texas.

Review by the US Supreme Court is uncertain. The latest decisions in all the states have been against the taxpayers. The Supreme Court usually focuses on cases where there is disagreement among courts that have considered an issue.

The Minnesota Supreme Court heard oral arguments in January in another multistate compact case in that state involving a $1.2 million refund claim by Kimberley-Clark. The company argued it overpaid income taxes in the state between 2007 and 2009 because it should have been allowed to use the formula in the multistate tax compact. The Multistate Tax Compact filed a brief supporting the state's position that Minnesota remains free to alter the formula in the compact.

At least five companies have asked the Michigan Supreme Court to review a state appeals court decision in September in 50 consolidated tax refund cases by multistate companies that the companies were not entitled to continue using the three-factor apportionment formula in the multistate compact after the state switched to a sales-only formula. The / continued page 21

New Trends Shaping the 2016 Market

Two investment bankers, a consultant and a market analyst had a wide-ranging discussion at the Infocast power & money conference in New Orleans in January about new trends that are shaping the US power market and what type of year they expect in terms of deal flow.

The panelists are Ted Brandt, CEO of Marathon Capital, Peter Kelly-Detwiler, a principal with consultancy Northbridge Energy Partners, Andy Redinger, managing director and group head of utilities and alternative energy at KeyBanc Capital Markets, and William Nelson, director of analysis, North America, for Bloomberg New Energy Finance. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Ted Brandt, what are the new trends this year in the market?

MR. BRANDT: The Christmas or Hanukkah present that we all got when Congress extended the renewable energy tax credits on December 18 is probably the most significant event for many of us. My phone started ringing after that. Renewable energy developers believe their companies are more valuable now. They have moved away from wanting a liquidity event and are starting to focus on raising new capital. The new question among developers is how to scale up to take advantage of this new period of certainty.

MR. MARTIN: Peter Kelly-Detwiler, Ted says the new trend is renewable energy developers are refocused on growth. Are there other new trends?

MR. KELLY-DETWILER: I think the trend this year is the same as last year, which is the continuing spread of distributed energy. Solar obviously remains big. Storage is starting to creep out of the den. We will see the infusion of IT into everything. Use of distributed energy equipment will be much more interactive with the grid. We are just starting to see innovation because of high-performance computing. The ability of computers to perform tasks will increase a thousand times and open up new vistas.

MR. MARTIN: So it will be distributed energy on steroids with the help of high-performance computing. Andy Redinger?

MR. REDINGER: Community solar will continue to grow in appeal. More states will pass legislation to permit it; there are probably a dozen today. I agree with Ted Brandt: another trend this year will be raising capital. Interestingly, at the same time developers will be out searching for equity to grow, debt to finance their projects is becoming more expensive. And the market will figure out how to finance commercial and industrial solar projects at greater scale.

MR. MARTIN: So community solar and C&I solar will get traction and everybody will be raising capital. Will Nelson, other new trends?

MR. NELSON: Low gas prices seem here to stay. We entered last year, after two abnormally cold winters that masked the oversupply in the natural gas market, with the question whether gas would be above or below $4. As we start 2016, the question is whether gas will be above or below $2. This makes for a very different power market.

The next trend is greater certainty for the renewable energy market. The tax credits have been extended for multiple years. State targets have been set under the Clean Power Plan for carbon emissions reductions. It remains to be seen how the plan will be implemented, but the trend is toward greater certainty.

It seems like we have greater certainty than normal on the wholesale side with volatility on the retail side. Virtually at the same time that Congress extended the renewable energy tax credits, there were significant rulings in California and Nevada about net metering, with California deciding largely to preserve its existing net metering program and Nevada coming down on the other side. The battles are just starting around retail rate structures.

Deal Flow

MR. MARTIN: Starting again with Ted Brandt, what do you think will be the deal flow this year? What types of deals do you think will dominate?

MR. BRANDT: The renewable energy sector will be not be as frantic to close deals this year as it would have been had the solar tax credits expired at year end. We were in a 2016-or-bust market, so the behavior of most developers, with maybe one or two exceptions, was not to spend a lot of development capital on things that were going to happen past the cliff.

As a consequence, development pipelines are pretty shallow today, so we should see a lot of new development and lots of people looking for new power purchase agreements. I expect most of that stuff to start hitting the market in 2017.

MR. MARTIN: Andy Redinger?

MR. REDINGER: Our pipeline is as strong as it has ever been, but we are looking ahead only as long as six months. We think the first half of 2016 will be better than the first half of 2015, but we are struggling to see how 2016 as a whole can be stronger than 2015 as a whole. We are worried about the second half of 2016 in terms of deal flow.

MR. MARTIN: Andy Redinger, sticking with you, last year was a busy year for financing LNG export terminals. Those were multibillion dollar financings. Merchant gas projects were another big part of the market and then renewables. Is it just renewables this year? Is that all that is left?

MR. REDINGER: No. There are still some gas-fired power plants to finance, but the market is definitely getting tired. It will largely be renewables this year and be focused mainly on rooftop solar and other forms of distributed energy.

MR. MARTIN: One challenge with financing merchant plants is the need for a hedge to put a floor under the electricity price, and hedges seem in short supply.

MR. REDINGER: There are hedges, but if you are trying to get one in ERCOT where everyone else is trying to do merchant deals, good luck. I think if you go to PJM or you go to one of the other liquid markets, there is capacity.

MR. MARTIN: Where else can one finance merchant power plants besides ISO New England, PJM and ERCOT?

MR. REDINGER: That is probably it.

MR. MARTIN: Let me challenge some of you on what you said are the new trends this year. Peter Kelly-Detwiler, you think distributed energy will continue to gain traction fueled by use of information technology and big data. What happens to your prediction if states start rolling back their net metering programs?

MR. KELLY-DETWILER: Some states will preserve net metering, and other states will be a mess. Look at Hawaii, which rolled back net metering in late 2015. We are already hearing reports of rogue installers who are installing solar systems with batteries that let homeowners drop off the grid altogether.

Once the cost of storage creeps below $500 a kilowatt, which is what Schneider Electric says it can now do with the EcoBlade, the market will grow. In states where net metering disappears, I think you will see homeowners using rooftop solar with batteries to take greater advantage of arbitrage opportunities. This is already a huge market in Australia.

Community Solar

MR. MARTIN: Andy Redinger, you are predicting that community solar will start to take off in 2016. What is preventing community solar developers from getting financing */ continued page 22*

IN OTHER NEWS

companies all have large sales, but little payroll or property in Michigan. Michigan is facing as much as $1.1 billion in refunds if it loses in the courts.

The Michigan Supreme Court may wait until the summer to decide whether to hear the appeal. It held in another case in July 2014 that IBM was entitled to use the three-factor formula for calculating its taxes in 2008 after concluding there was no evidence that the state legislature wanted to repeal the multistate compact provision allowing companies to elect use of the three-factor formula when it adopted a single-factor approach in 2008. The state legislature responded to the Supreme Court decision by quickly repealing the multistate compact retroactively the start of 2008.

A TAX EQUITY PARTNERSHIP sold state tax credits rather than allocated them to the tax equity partner, a US appeals court said in January.

The partnership had to report a $3.8 million "capital contribution" by the tax equity investor as income.

The decision is a reminder that there must be more substance to a tax equity transaction than stripping tax benefits.

Two individuals formed a partnership called Route 231 in 2005 to acquire two tracts of land near Albemarle, Virginia and then contribute conservation easements on the land to the Nature Conservancy and to one of the counties where the land was located. Virginia allowed a tax credit for 50% of the value of any conservation easements donated by property owners to conservation agencies.

Under Virginia law, any partner allocated conservation credits by a partnership can sell the unused credits to a Virginia taxpayer.

Another partnership called Virginia Conservation was interested in the tax credits and became a partner in Route 231. Route 231 allocated it 1% of income and loss and most of the Virginia tax credits. Each of the two individuals who were the other partners in Route 231 retained a 49.5% interest. */ continued page 23*

New Trends

continued from page 19

today for their projects? They have struggled.

MR. REDINGER: The offtakers don't have investment-grade ratings. The financial community is still struggling to figure out how to finance long-term revenue streams from unrated entities. It makes no sense to look at entities' debt ratings once at closing and then lend to them for the next 18 years with no obligation to maintain a stable debt rating after closing. One way to handle this may be to limit the percentage of unrated offtakers to a number, say 20%.

MR. MARTIN: There are different community solar models. In some states, like Minnesota, the utility stands ready to take the electricity at avoided cost to the extent that subscribers default. Isn't that the answer?

MR. REDINGER: That helps and may determine how big a bucket of unrated assets we can have, but the fact that the utility will take the electricity at avoided cost does not eliminate the uncertainty around the revenue stream. I don't know what the avoided cost is eight years from now.

MR. MARTIN: You are also bullish this year about the C&I solar market. The challenge there has been lawyers. Every customer agreement is different because the customers want to negotiate the solar power contract or lease, and this makes financing a portfolio of C&I solar installations expensive. The transaction costs become prohibitive when forced to do diligence on a portfolio of deals with multiple forms of contracts. What will change to make this take off?

MR. REDINGER: It's just a learning curve, I think. As we all do these deals and get smarter, I think everyone will get more efficient.

MR. MARTIN: Ted Brandt, do you see C&I solar taking off this year?

MR. BRANDT: I do. There is strong demand for the product, and we are seeing capital for it. We did two capital raises last year, just the way Andy described, that allowed up to 20% of non-investment-grade credits in the deal. There is no question that standardizing documents and trying to build a diversified pool will also help. The transaction costs are still too high and a lot of people have broken their picks on the market, but I think it is coming.

MR. NELSON: Let me go back to community solar. Distributed solar is an exciting new player in the independent power market. When we try to model how rapidly this market will grow, we have tended to use a consumer adoption model similar to how we might model the rise of cell phones. You are thinking about individuals adopting solar on their roofs. A key variable in these models is the maximum number of rooftops that can handle solar. We rule out rooftops that are too shady, or not strong enough to handle solar, etc.

What is interesting about community solar is that everyone can have access to it, so it boosts the potential pool to 100%. It feels like it can be a model breaker, which is why we are all so excited about it. The pull of community solar to investors is its potential to reach 100% of the population. But the issue, back to Andy Redinger's point, is every forecast for community solar has been too bullish and it eventually comes back to the point of every offtaker being different.

> Renewable energy companies will turn to raising new capital to dive back into project development.

MR. MARTIN: Will Nelson, as we start this week, natural gas prices are hovering above $2 an mcf. You think $2, or even sub-$2 gas, is here to stay and "this makes for a very different power market." How so? Play it out for us.

MR. NELSON: Low natural gas prices are making it more difficult for utility-scale renewable energy projects to compete, but they are not putting a dent in the distributed solar business. The wholesale gas price is about a third of your average retail electricity bill. The distributed solar companies are insulated by the wires business, which still occupies two thirds or so of the total cost, and that share is probably growing. The high wires cost is boosting retail rates and creating opportunity for distributed solar.

MR. REDINGER: The interesting question is with gas prices so low and wires costs so high, why isn't someone developing a gas generator for your house?

MR. MARTIN: It is called a fuel cell.

MR. REDINGER: Yes, but those are a little expensive. I am talking about a generic turbine in your basement. With gas prices expected to remain low and the power companies increasing your rates, eventually someone is going to say: "You know what, I am going to go off grid and hook myself up to the gas line. I don't need both a gas line and a power line into my house."

MR. MARTIN: Maybe people don't believe that low gas prices are here to stay or else they would do that.

MR. REDINGER: Maybe it has not caught up with them yet, but that thinking will become more prevalent.

MR. MARTIN: Do you have a gas generator in your house? Do you have a solar panel on your roof? Which bet have you made?

MR. REDINGER: I live in Ohio. We have 66 sunny days per year, so the answer is no solar panels.

MR. KELLY-DETWILER: I think you will see more on-site microgeneration. I visited a company in California, run by a bunch of PhDs out of Stanford, that has developed a really high-efficiency gas-fired generator that the company expects to bring to the commercial market in the next few years. I see this whole thing fracturing big time based on different market issues . . . .

MR. MARTIN: This "whole thing" means the centralized utility?

MR. KELLY-DETWILER: Yes. Pay attention to the Reforming the Energy Vision, or REV, proceeding in New York. One thing that may come out of that is heavier use of super IT infrastructure like a geographic information system that does a better job of collecting and acting on data. A utility will no longer have one avoided cost, but it will have thousands of them depending on the location of the customer. That means it might not make sense economically to put gas-fired generation in one neighborhood, but distributed generators could make sense in the neighborhood one street over. We are going to see a very different world start to emerge in the next five years.

Yield Co Taint

MR. MARTIN: Next topic. Yield co share prices collapsed starting around July 20 last year. SunEdison's share price dropped as well, and the rest of solar stocks were also battered. Why should what happened to SunEdison infect the entire sector?

/ *continued page 24*

IN OTHER NEWS

The partnership agreement required Virginia Conservation to contribute 53¢ to Route 231 for each dollar of Virginia tax credits allocated to it. Virginia Conservation ended up being allocated $84,000 less in tax credits in 2005 than what its $3.8 million capital contribution suggested. The partnership shifted tax credits to Virginia Conservation that had been allocated to the one of the two individuals before filing the 2005 partnership tax return to make up the shortfall.

The IRS said the arrangements were in substance a sale of tax credits to Virginia Conservation. A US appeals court agreed in early January. The US Tax Court reached the same conclusion in 2014. (For earlier coverage, see the April 2014 *NewsWire* starting on page 21.)

IRS regulations say the government will assume any partner who contributes property to a partnership — in this case, the two individuals were viewed as contributing state tax credits to Route 231 — and then is distributed cash within two years that was contributed by another partner made a sale of the property to the partnership, unless the parties can show there is no link. The US appeals court said the state tax credits are "property" for this purpose. It said the capital contributions were clearly a payment for tax credits.

The court pointed to a number of facts that support treating the transaction as a sale of tax credits.

The capital contributions were X¢ per dollar of tax credits.

Virginia Conservation had a right to be indemnified by the other partners if the tax credits fell short. There was an agreement by one of the other partners to reduce his share if necessary to top up what Virginia Conservation was allocated to ensure it got the full amount of tax credits for which it paid.

The lopsided allocations did not help. Virginia Conservation was allocated only 1% of income and loss, but 97% of tax credits.

"At bottom," the appeals court said, "Virginia Conservation's right to the tax credits depends on fixed contractual terms, / *continued page 25*

New Trends

continued from page 23

MR. BRANDT: We released a white paper that some people may have seen. Investors did the math; they calculated the discount rates at which yield cos would have to buy new assets in order for acquisitions to be accretive to shareholders while selling more shares in the secondary market to raise capital to make the acquisitions. The math didn't work. The whole think blew up after about the second deal. It was inevitable that things would come back to earth and that dividends would move closer to where they are today.

The problem was not isolated to SunEdison. Everybody looked around and said that these acquisitions cannot possibly drive growth to a point where the growth justifies a 2% dividend. The market probably over-corrected.

We are still long-term bullish that the public yield co dividend-paying model is the right way to own these assets and that it provides the cheapest form of capital, but clearly we have had a painful last seven months adjusting to get the math right.

MR. MARTIN: Andy Redinger, you have been the most articulate advocate for yield cos. You helped create the first one. What is the attraction to sponsors if yield cos become sleepy vehicles for predictable cash flow? Will that be the cheapest source of capital as Ted Brandt said?

MR. REDINGER: Yield cos are publicly-traded infrastructure funds. There are billions of dollars available to invest in this sector. Yield cos compete with others for this capital. You do not have to look very far north of the border to see several Canadian income trusts trading very well on the same type of assets that are owned here in the US. It is not clear why our assets should trade differently than the assets that they hold. Some rationality will eventually return in the US market.

MR. MARTIN: Does it make sense for a solar company looking today for a way to monetize its operating assets to form a publicly-traded yield co to buy them?

MR. REDINGER: Yield cos were formed originally as a tool. They were not formed to be the exclusive off ramp for solar developers to monetize their assets. The developer should sell its assets to the highest bidder. The highest bidder could be an affiliated yield co or it could be an infrastructure fund.

Discount Rates

MR. MARTIN: Ted Brandt, what discount rates are people using today to buy renewable energy projects?

MR. BRANDT: I would normally give you a forthright answer based on having looked at a lot of deals. Last year was a Charles Dickens tale of two periods. There were lots of sales in the beginning of the year. There were few at the end of the year.

My sense is that a contracted wind project would trade today at an 8 1/2% to 9 1/2% discount rate, unleveraged, after-tax based on a 30-year pro forma. Solar is 100 to 125 basis points below that.

For wind, that range is not terribly different than where we have seen discount rates for a number of years, but the rate for solar is about 50 basis points higher than where we saw solar discount rates bottom out.

MR. MARTIN: I was going to say it a little differently. That is where rates were before yield cos took off.

MR. BRANDT: It makes sense. Obviously, if the yield cos come back, there may be some compression, but we are watching solar assets that were getting done at 6 3/4% trade today at 7 1/4%.

MR. MARTIN: Let's go back to the original question, because I don't think I got an answer. Why did the troubles that SunEdison ran into when the TerraForm Power share price collapsed, and that NRG ran into when the NRG Yield share price collapsed, infect the entire solar rooftop sector?

MR. BRANDT: It is like asking why does oil affect the entire market in today's equity markets. There is no good answer to that other than that is how the markets work.

It is a catalytic effect. I had more hedge funds call me and ask, "What the hell is going on?" "I don't know what the hell is going on. But let me tell you about this company, this company, this company . . . ." The whole sector went in the other direction. I don't know whether it is tied to oil, but there is a perception on Wall Street that if oil prices are at $25 a barrel, then renewables must suck.

One narrative is to look at Vivint. The deal TerraForm cut to acquire Vivint exposed some very aggressive assumptions that I think SolarCity and Sunrun were also applying, and so the spotlight on Vivint reached SolarCity and Sunrun even though they are very different companies. The questions included where are you going to build all of the new solar that you claim to be building? They all have aggressive growth targets. California is carrying the entire industry. What are the new states that will support the growth these rooftop installers expect?

MR. MARTIN: What should investors in the rooftop sector make of the net metering debate that is spreading across the country?

MR. REDINGER: You could see it coming. Utilities were not going to sit by and watch their customers walk out the door. It should not surprise anybody that this conversation is happening. That said, I am comforted by the strong support there is at the federal level and in a lot of states for solar. You just need to pick your spots. I would not overreact. The solar rooftop business is not in danger of disappearing. The net metering debate is something to be concerned about, but ultimately, the public will win this debate. If the end result is that the public finds a cheaper way of procuring power, then in the long term, the solar rooftop companies will be fine.

MR. KELLY-DETWILER: The lack of grandfather relief in Nevada was painful and sent chills through the industry. I own five solar panels in a virtual net metering community solar project. The Nevada decision makes me think that perhaps I made a bad investment. If I am thinking that, then others are probably also thinking it. [*Editor's note: Nevada originally decided to reduce net metering benefits for all solar customers, but as the* NewsWire *went to press, it was considering grandfathering customers who bought or leased rooftop solar systems before the new rules were imposed on January 1.*]

The other thing to keep in mind is that we are not done yet with declining costs around balancing systems and even for the panels themselves. I just visited a manufacturer, 1366 Technologies, that believes it can cut the cost of silicon PV wafers that account for half the cost of a solar module by 50%. Even though the economics on the retail side may deteriorate, the costs of solar equipment will continue to decline. There is a horse race among competing technologies.

MR. MARTIN: So the declining equipment cost can compensate for the loss of net metering benefits.

MR. KELLY-DETWILER: At least to some degree.

MR. MARTIN: While the net metering debate is important, if the grandfather rules work properly, then solar companies should be able to continue working in a state at least until the law changes.

MR. KELLY-DETWILER: Exactly.

Energy Storage

MR. MARTIN: Next topic, energy storage. A lot of people think storage is a transformational technology. There seem to be two market segments for storage. One is adding batteries to rooftop solar systems and utility-scale wind and solar projects, and the other is standalone 20- and 30-megawatt batteries that are interconnected with the grid in order to help balance the grid. I have heard some CEOs say that the */ continued page 24*

IN OTHER NEWS

not the entrepreneurial risks of Route 231's operations." The case is called *Route 231, LLC v. Commissioner.*

OREGON is considering how to deal with an overhang of unused BETC tax credits and is also investigating potential wrongdoing in the program.

The state rewarded owners of new renewable energy projects in the state through a business energy tax credit — called BETC. The program ended in 2014.

Developers who were unable to use the credits could sell them. Sales could be arranged through the Oregon Department of Energy or privately. The Department of Energy had a formula for setting the sales price. DOE rules required private sales to be at the same price, but the department decided not to enforce the requirement, and private sales were sometimes at prices that were well below the formula price.

A January 14 hearing before an Oregon house committee disclosed that $44 million in credits are still being held by taxpayers who lack the tax capacity to use them.

The state is considering three options.

One is to change the formula to reduce the floor price.

Another option is to let holders of the tax credits sell at whatever price they can get in the market. Critics charge that private sales at low prices mean that too little of the intended subsidy ends up with renewable energy companies. The Department of Energy has already proposed amending its rules retroactively to drop the requirement that private sales be at the formula price.

The last option is to have the state buy them at less than the full tax credit amount. The thought is the state would save money since credits would otherwise reduce tax collections by the full face amount.

The Oregon secretary of state, a Democrat, has asked the state energy department for records relating to private sales, including notices from developers who were */ continued page 27*

New Trends

continued from page 23

standalone storage market is tiny. The frequency regulation market in PJM is not far from being saturated after being in play for only a short time. Which is storage: a transformational technology with enormous potential or a small niche market?

MR. KELLY-DETWILER: If you talk to somebody like Schneider Electric, they think that it is a $20 billion-a-year market just for backing up IT and cloud-based data centers. If you talk to somebody like AES Storage, they think every time there is a bid for a new gas peaker, they can win with storage, and the cost of storage keeps falling. I agree with you that the frequency regulation market is saturated because it is a small market, but that is not where the major value proposition is for utility-scale storage on a go-forward basis. It is grid stabilization. As you see more wind and solar coming on to the system, there will be an increasing need for storage.

MR. MARTIN: So the biggest market for standalone storage — not as an adjunct to a wind or solar project — is replacing peakers?

MR. KELLY-DETWILER: That is what I am hearing.

MR. MARTIN: What about adding batteries to solar rooftop systems? Peter Rive from SolarCity said last June that it will be five to 10 years before it will be economic to add batteries routinely. A $5,000 battery today produces only about $500 in time-of-use savings over the lifetime of the system.

MR. KELLY-DETWILER: The solar companies say that at $1,000 for a battery, there is no market, but when you push the cost down to $400 or $500, then there starts to be a real market.

These are Lego building blocks: solar, storage, even wind. You need software that ties everything together. The software that makes it all smart is only beginning to emerge. Combining solar with storage is one plus one equals at least two and a half because of the demand charges and the ability to optimize, particularly when you get rid of net metering. How these markets develop will vary by location. Like any other emerging technology, it will hit the beaches and eventually infiltrate and spread in ways that are not entirely foreseeable.

MR. MARTIN: How does it help, if your customer is losing revenue because of a scaling back of net metering, to add to the capital cost to the system?

MR. KELLY-DETWILER: It depends on who is financing the system. I do strategic consulting for companies in the solar sector, and they are all looking for opportunities to provide adjacent services. Each has a core competency. For example, Johnson Controls is one of the largest battery manufacturers in the world. It knows buildings. It knows control systems. It is looking at opportunities to plunk batteries in its customers' buildings. Sharp is saying the same thing. Sharp says it has $100 million worth of financing lined up for storage. Stem has $85 million worth of financing. A bunch of those companies have money, and they are ready to start deploying batteries today: up to $5 million apiece for commercial and industrial flow batteries onsite.

Community solar will take off in 2016 as banks and tax equity investors master the financing issues.

MR. NELSON: The question is why increase the capital cost of a rooftop system by adding a battery at the same time that a rolling back of net metering is reducing the potential revenue from use of the system.

The answer is the grid is a free socialized battery under net metering. There is no reason to add a storage system if the grid is providing you free storage. If you take away free storage, then many customers will decide storage is a benefit for which they are willing to pay.

The move toward imposing a fixed charge or capacity-based charge to disincentivize solar is starting to incentivize adding storage. There is an interesting synergistic relationship between solar and storage. It shows up in many places. This is just one of them.

The Big Picture

MR. MARTIN: Let's step back and look at the big picture. There is very slow growth in demand for electricity in the United States: .7% to .9% a year. We have three types of entities competing for market share. There are distributed generators, the regulated utilities and the independent power companies. The independent power companies have made inroads this past year by bypassing the utilities and going directly to the customers by signing commercial PPAs. In 2015, 3,160 megawatts of such PPAs were signed, which is more than double the amount the year before.

How do you see the battle for market share among the three groups playing out? Who is in the ascendancy? For the longest time, it was a battle between regulated utilities and independent power companies, and their market shares remained remarkably stable.

MR. BRANDT: One of the things that we are hearing over and over again from calling on strategic planners at utilities is that the Clean Power Plan has given utilities an incentive to build rate-based renewables in a very big way. So we are watching utilities, like MidAmerican, planning to add renewables, but within the rate base.

At the same time, we are also seeing other, slow-growing utilities develop NextEra envy. NextEra is getting the same multiple on its IPP business as it is on the utility business. Its earning are now divided about 50-50 between the two businesses. A number of regulated utilities are moving in a serious way into the IPP business and adding contracted assets, even to the point of buying developers or trying to make investments in developers' assets. So my bet is the IPP business will continue to grow. I think the distributed generation business will continue to eat away a bit at the utility business, but I think all three models will coexist for the next number of years.

MR. MARTIN: The IPP business will grow because the regulated utilities will put more effort into unregulated affiliates that compete outside their service territories?

MR. BRANDT: I think so. They have incredible advantages.

MR. REDINGER: We cover 52 regulated utilities, and we are seeing the same thing Ted just mentioned. They are asking us to help them by bringing opportunities outside their service territories.

MR. MARTIN: How big an inflection point will it be in 2016 if the US states that are in court trying to block implementation of the Clean Power Plan win? Would it make a difference?

/ continued page 28

IN OTHER NEWS

planning private sales. Some Republican state legislators said earlier they "might consider" legislation to take back some of the tax credits sold at low prices. The chairman of the house energy committee says the push for clawbacks is more or less a dead letter. The Oregon secretary of state issued a request for proposals in early February from forensic auditing firms to sample 12,000 BETC applications the state received under the program to look for signs of possible fraud or wrongdoing before undertaking a full-scale review of all the applications.

There have been 43 audits of BETC transactions by the state Department of Revenue. The department found in 20 of the audits that buyers of the tax credits underpaid capital gains taxes when they used the credits.

Five state Republican legislators are calling for a criminal investigation by the state attorney general into whether DOE employees allowed holders of the tax credits to sell them at prices below the state-mandated levels and whether sellers failed to report the sales proceeds as capital gains.

The IRS said in an internal legal memorandum in 2011 that someone who buys a state tax credit has a capital gain, when he uses it, equal to the difference between the state taxes the credit offset and the amount he paid for the credit. Thus, for example, a buyer who pays $70 for a $100 tax credit has a capital gain of $30 when the credit is used. (For earlier coverage, see the May 2012 *NewsWire* starting on page 19.)

A BOTCHED INVERTED LEASE was given more time.

Parties to two tax equity transactions structured as overlapping inverted leases for what appear to be solar equipment were given more time by the IRS to file paperwork to make the transactions work.

The IRS granted the extra time in two private rulings that were made public in mid-December. The rulings are Private Letter Rulings 201550023 and 201550024.

In an inverted lease, a / continued page 29

New Trends

continued from page 27

MR. BRANDT: We have a coal company as a client. It is selling a slice of a supercritical coal plant to an electric coop. They have been saying is that there is just no good news in coal. Forget the Clean Power Plan. They are having their lunch eaten by cheap natural gas. At $2 gas, especially with the new class of gas turbines, the low cost producer by $10 to $15 a megawatt hour in every market is gas. Regardless of whether the Clean Power Plan is implemented, coal is in a downturn anyway. You are going to lose it on a pure economic calculation. Forget about the environmental issues.

MR. MARTIN: So the loss on the Clean Power Plan would not make much difference? The trend lines are already set?

MR. BRANDT: I am sure it would make a difference, maybe in terms of the rate of change in some areas, but I am not buying coal stocks today.

MR. MARTIN: When a Trump, Cruz or Rubio administration on its first day in office reverses everything that Obama has done, it will not make much difference? Coal is on its way out anyway?

MR. BRANDT: I think at worst it would just postpone the inevitable.

MR. MARTIN: Next topic. A lot of developers seem to be rushing south of the border into Mexico. Good idea?

MR. BRANDT: We closed a deal in Mexico last year that took us 31 months to close. We had to go through two different federal law changes and deal with indigenous people that may have traversed the site to a sacred burial ground 600 years ago. We were very happy that the deal closed. I can only say it's a long, long way away from being anything close to a mature market. To say that everything takes longer is an understatement.

Mexico needs the power as poor people become middle class and as middle class become upper class. Mexico's economy is growing at 1% to 2% a year, and demand for electricity is growing by 8 1/2% a year. In that respect, it is a completely different market than the United States. It desperately needs power. You are largely displacing very inefficient oil-based generation at the margins. Mexico wants the renewable power. However, it is more challenging to displace oil when oil is at $25 a barrel than when it was at $100.

MR. MARTIN: Next question. Do you think there will be more interest among foreign pension funds in investing in US infrastructure projects after Congress voted in December to waive capital gains taxes on such pension funds when they exit US investments?

MR. REDINGER: We have seen growing interest over the last couple years from foreign pension funds. Will this help? Yes, but the foreign pension funds were already headed in this direction.

MR. MARTIN: So not much change. What really moved the meter?

MR. BRANDT: The equity markets stink. Having 9% long-term infrastructure returns is the attraction.

MR. MARTIN: Next question. Wholesale power prices fell sharply in 2015. New power contracts signed were at very low prices: $40 a megawatt hour for solar and in the low $20s for wind. How much will that offset the boost that would otherwise be expected from extending tax credits for renewable energy?

MR. REDINGER: It comes down to the math. No doubt it will reduce the number of opportunities to build new projects because of declining revenue. On the other hand, equipment costs continue to fall. We have seen developers sign power contracts with low net present value day one, but by the time they are ready to build and are done adding value through the financing, equipment procurement, the EPC contract, etc., they have figured out how to pull a decent net present value for project.

MR. MARTIN: Oil prices. Iran is now able to sell its oil on world markets. It is planning to increase production. What effect, if any, will this have on the US power market?

There should be a larger market for distributed gas generators in view of the low gas prices and high retail electricity prices.

MR. NELSON: We do a long term gas forecast in the US on a play-by-play basis. The question is what gas-break-even price is needed to bring marginal wells online, just like a merit order for power.

We thought falling oil prices would cause loss of the associated dry gas and wet plays that no one will be able to tap into any more, but what was actually a much stronger impact, and was pretty surprising to us, is the drop in rig counts to drill wet plays for oil means that rigs are freed up for pure gas drilling. The cost of drilling for gas has fallen by about 30%, meaning we can drill gas 30% cheaper today because we have so many rigs sitting around idle, and that fundamentally is what drove the decline in gas prices last year throughout the US.

Any further slack in the rig count in the US should drive lower prices for rigs, drilling and completion and ultimately gas. How that translates to power is obvious.

MR. MARTIN: What is the correlation, if any, between oil prices and natural gas prices?

MR. NELSON: The fall in oil prices cut gas drilling and completion costs by 30%. The correlation has to do with our rigs being taken away to be used for wet plays in oil. Or do we have spare rigs that can now be diverted to pure gas plays.

Postscripts

MR. MARTIN: We covered a lot of ground today both in this panel and in the briefing that preceded it. You heard that the fate of the Clean Power Plan, which would force reductions in carbon emissions and faster retirements of coal-fired power plants, will be decided perhaps as early as September by the courts. Wholesale power prices are falling sharply. Renewable energy tax credits have been extended. About half the states with net metering are expected to revisit their rate structures this year. We talked about why it has been so challenging for community and C&I solar projects to secure financing, and how these markets might find a path forward. The financial community may be feeling it has enough exposure to merchant gas-fired power plants in PJM, but there may be room for a few more, especially in ISO New England and ERCOT. It is getting harder to find power hedges in ERCOT. Andy Redinger suggests that bank interest rates are going up because banks are having to pay higher costs of funding. Is there anything else to add?

MR. NELSON: Cheap gas is the most important story in the power mix right now. Gas prices look likely to remain low for a long time. The generous incentives for */ continued page 30*

IN OTHER NEWS

solar company leases solar equipment to a tax equity investor. The parties agree in writing that the lessor will pass through the investment tax credit on the equipment to the tax equity investor as lessee. The lessee then files that statement with its tax return for the year the transaction closes.

In the two transactions, both the lessor and lessees were partnerships. Each lessee was a partner in the lessor.

The parties failed to do the proper paperwork to transfer the investment tax credits to the lessee. Instead, each lessor partnership allocated the full credits to the lessee in its capacity as a partner in the lessor.

The IRS may have raised questions on audit.

The parties then asked the IRS national office in Washington for more time to put the paperwork in place. The IRS gave them 120 days after the rulings were issued. The agency said it will grant companies more time in cases where "the taxpayer acted reasonably and in good faith, and . . . granting relief will not prejudice the interests of the government." In this case, the tax credits had already been claimed.

CONVERSIONS OF US UTILITIES INTO REITS may be less common after Congress acted in December.

However, at least two conversions remain in the works in Texas.

CenterPoint Energy, a large electric and gas utility headquartered in Houston, said in early February that it is exploring whether to put its transmission and distribution assets under a real estate investment trust. The move could help it save on taxes. A REIT is a corporation or trust that is not taxed on its earnings to the extent the earnings are distributed each year to the owners. Wells Fargo Securities said in a report that the move would provide a "potential value uplift" to the utility.

A group led by the Hunt family that is competing to buy Energy Future Holdings, another utility headquartered in Dallas, has applied to the Public Utility Commission of Texas to convert the company */ continued page 31*

New Trends

continued from page 27

renewables are helping to offset cheap gas, but renewables may struggle once the tax credits go away.

MR. MARTIN: Perhaps some good news, Will Nelson, is the US Senate is debating an energy bill this week that would make it easier to get licenses to export gas.

MR. REDINGER: The one thing you did not mention is I would have thought we would be in the midst of a wave of consolidations by now, but the foot appears to have come off the accelerator. I thought this was going to be a big M&A year. Now I don't think it will come close to what it could have been.

PETER KELLY-DETWILER: I think the panel did a good job of identifying the major trends for the year ahead. Long term, I think it is easy to think we live in a snap-shot world, but we don't. We live in a motion picture world where the frames are accelerating, particularly with respect to the innovation dynamics. The technologies and trends we will see five years out will surprise us. There are emerging technologies that we do not even think about today, and the ones we do know about today are going to be enhanced in terms of effectiveness and lower cost.

MR. BRANDT: We do not stop often enough to reflect on the fact that the contracted assets in this industry have performed really well. The investors have pretty much gotten what they expected. I look at the public equity markets. Last year, the Dow was down. This year, it is already down dramatically. We see more and more long-term coupon-clipping investors coming into the sector. The money will be there. The tax credit extensions will give renewables quite a jolt for the next few years. A lot of projects will be built over the next few years. Maybe there will not be as much M&A in 2016, but over time renewables are a consolidating business and the capital will win out.

MR. MARTIN: So long term, great outlook, particularly for renewables; 2016 will be a good year, but probably not a record year. ◎

Multilateral Development Bank Update

by Rahwa Gebretnsaie, in New York

Major developments in the agency lender market will emerge in 2016.

The launch of the Asian Infrastructure Investment Bank (AIIB) by China and the New Development Bank (NDB) by the BRICS countries (Brazil, Russia, India, China and South Africa) will create new sources of finance for energy and infrastructure projects.

The consolidation of the private sector operations of the Inter-American Development Bank (IDB) into the Inter-American Investment Corporation (IIC) will be accompanied by increased capitalization for the IIC and new form contracts for its debt and equity instruments.

Asian Infrastructure Investment Bank

The AIIB was conceived by China as part of a "one belt, one road" strategy to develop trade routes to Europe and promote interconnectivity and economic integration in Asia. For more background information about the AIIB, see "China Launches a Multilateral Infrastructure Bank" in the July 2015 *NewsWire* starting on page 77.

The board of governors of the AIIB declared the bank open for business on January 16, 2016 during the inaugural meeting of the board.

The bank will have an initial authorized capital stock of $100 billion, with 75% of its initial capital subscription allocated to regional member countries. China is the largest country shareholder, holding 30% of the initial shares.

The AIIB is open for subscription by members of the World Bank and Asian Development Bank. There are currently 57 member countries, including Germany, the United Kingdom and the BRICS countries. Germany plans to make a capital contribution of $900 million to the AIIB over the next three years, in addition to a $3.6 billion guarantee to the AIIB in 2016.

The first batch of AIIB loans is expected to be approved in mid-2016.

The bank's lending currency will be US dollars. Borrowing terms are expected to be similar to terms on offer from other multilateral lending agencies.

chadbourne

The AIIB will focus on the development of infrastructure and other sectors in Asia, including energy and power. AIIB-eligible borrowers must be either member countries, agencies or enterprises in member territories as well as international or regional agencies or entities concerned with the economic development of the region.

The AIIB's lending policies, including its policy on finance and pricing, operational and corporate procurement, and environmental and social framework, are currently being developed by its board of governors. The board has not yet decided whether the AIIB will finance coal and nuclear projects. It has indicated an intention to be a green institution built on respect for the environment. This could disappoint countries with cheap fossil fuels that are currently prohibited from accessing debt finance from existing agency lenders, such as the International Finance Corporation, due to restrictive environmental policies of the existing agency lenders.

The AIIB board is working with the European Bank for Reconstruction and Development, Asian Development Bank and World Bank to ensure that its policies follow agency best practices. Such cooperation and harmonization of the AIIB's policies will be critical in determining its ability to co-lend with existing multilateral development banks.

The United States has not subscribed to AIIB shares. The US Treasury secretary, Jack Lew, said the US is ready to welcome new institutions such as the AIIB, provided that they "complement existing international financial institutions and that they share the international community's strong commitment to genuine multilateral decision-making and ever-improving lending standards and safeguards."

New Development Bank

The NDB was officially launched by the BRICS countries in July 2015.

The bank will issue loans, guarantees, equity participation and other financial instruments to borrowing member countries. It is unclear to what extent terms will vary from those on offer from other multilateral development banks. However, the increased supply of capital and new competition could help reduce capital costs for eligible projects.

The NDB's initial authorized capital is $100 billion, and initial subscribed capital is $50 billion distributed equally among its founding BRICS members. Membership in the NDB is open to all members of the United Nations.

/ continued page 32

IN OTHER NEWS

into a REIT that would hold the transmission and distribution assets of a subsidiary, Oncor, and then lease them back to what is currently Oncor. (For more details about how the deal would be structured, see the September 2015 *NewsWire* starting on page 15.)

The Public Utility Commission is expected to rule on the transaction in March. The PUC staff raised questions in a filing in late January about whether the move would leave the operating company that leases the T&D assets starved for cash to pay unexpected costs, like restoring service after major storms. It also suggested the operating company may end up collecting for federal income taxes from ratepayers that would not be paid, at least at the company level.

Congress voted in December to limit the ability of corporations to spin off assets or businesses tax free as part of a REIT conversion on or after December 7, 2015, unless the transaction is described in a IRS ruling request that was pending as of that date. The restriction is part of the tax extenders bill that extended expiring renewable energy tax credits in December.

The IRS had already put a hold on rulings about tax-free spinoffs of assets in situations where the company is not also spinning off other parts of the company, like customer relationships and employees, that are needed for an active business. The IRS put the subject on its latest business plan, which is a list of issues it hopes to tackle by June 2016.

In the typical utility REIT, passive assets like transmission and distribution lines and towers are put in a REIT and then leased to the operating company. The operating company uses them to serve customers and pays part of its revenue to the REIT as rent. The part paid to the REIT escapes a corporate-level tax.

Cell tower operator American Tower Corp. converted into a REIT in 2012 and reported $1.2 billion in tax savings through mid-2014.

Arkansas telecom company Windstream Holdings Inc. spun off its fiber optics and copper lines, real estate and other fixed assets in April 2015 into a separate */ continued page 33*

Development Banks

continued from page 31

The BRICS countries made their first capital contribution of $750 million to the NDB in January. The initial enthusiasm for the NDB has been tempered over the past year due to cutbacks in public spending among BRICS countries. The decline in oil prices has created economic challenges for the BRICS countries that may affect their lending practices in the short term. While the NDB expects to make its first loan in April 2016, its initial financial instruments may take the form of guarantees rather than direct lending as the BRICS recover from economic downturns.

The deficit in financing for infrastructure and power projects in emerging markets and developing countries creates significant opportunities for cooperation and co-lending among the multilateral development banks. By some estimates, emerging market countries need to spend $1 trillion annually to meet their infrastructure needs. The NDB plans to work with other MDBs to address this infrastructure gap; however, its cooperation may be limited to MDBs with minimal US ownership, such as the AIIB, as it purports to be "an alternative to the existing US-dominated World Bank and International Monetary Fund."

Complementary or Competitive?

The charters of the AIIB and NDB express a commitment to cooperate with existing MDBs. NDB President Kundapur Vaman Kamath said recently that "our objective is not to challenge the existing system as it is but to improve and complement the system in our own way."

The extent to which the AIIB and NDB cooperate with existing MDBs in fact will undoubtedly be affected by the bilateral relationships of their respective stakeholders.

Cooperation between the EBRD and AIIB is expected, given the shared priorities that China and European countries have in the central Asia region. The extent to which the World Bank and ADB will cooperate, and particularly co-lend, with the AIIB and NDB remains to be seen. While the World Bank President Jim Yong Kim and ADB President Takehiko Nakao have expressed optimism about the introduction of the new banks, their largest stakeholder countries, the United States and Japan respectively, are noticeably absent as members of either the AIIB or the NDB. As the credit, environmental and social policies of the AIIB and NDB roll out in 2016, we will see whether these new institutions will be positioned to cooperate or compete with existing MDBs.

Inter-American Investment Corporation

The board of governors of the IDB and the IIC agreed under a "Renewed Vision Merge-Out High Level Implementation Plan" to consolidate the bank's private sector operations into the IIC.

The IIC is the private sector arm of the IDB, in the same way the IFC is the private sector arm of the World Bank. Each provides capital directly to private developers and projects.

The IDB says the shift of the private sector operations to the IIC should decrease processing times for new projects by creating a single point of access for the full spectrum of products and services the IIC will offer to private sector clients. The newly consolidated IIC will receive a $2.03 billion capital increase and is currently in the process of developing new form contracts for its debt instruments.

The IDB is the largest regional development bank in Latin America, with 48 member countries, of which 26 are borrowing members. Two private sector operations are being moved to

Two new Chinese-backed development banks should become more visible in 2016.

the IIC. They are the IDB's structured and corporate finance department and opportunities for the majority department.

The IIC previously provided lending, equity investments and advisory services only to small and medium-sized enterprises in Latin American and Caribbean countries. Currently, the IIC has 45 member countries of which 26 are in Latin America and the Caribbean.

The IDB's structured and corporate finance department leads all non-sovereign financing operations for large infrastructure projects, financial institutions, capital markets, trade finance, companies and state-owned enterprises in a broad range of economic sectors.

The IDB's opportunities for the majority department promotes and finances market-based, sustainable business models that engage private sector companies, local governments and communities in the development and delivery of quality products and services for the base of the pyramid in Latin America and the Caribbean.

The administrative and operational functions of these operations have been merged under the IIC in an effort to promote internal efficiencies, flexibility and responsiveness to private sector client needs.

New Market Developments

The IIC is currently developing a suite of new form contracts for the various debt and equity instruments it offers.

The new form contracts are expected to be more market friendly and conform to agency lender best practices. The new form credit agreement is expected to be authorized for use within the first quarter of 2016.

The board of governors of the IDB and IIC resolved to increase the capital of the newly consolidated IIC by $2.03 billion. Of the $2.03 billion capital increase, $1.305 billion will consist of new contributions by IIC member countries and $725 million will consist of capital transfers from the IDB starting in 2018.

The IIC Board of Directors recently agreed to earmark a significant number of additional shares for China, Korea, Canada and Spain. The US remains the largest subscriber to IIC's capital stock, although Latin American and Caribbean member countries will continue to hold a majority stake.

The IIC's leverage policy limits debt to three times capital. As of April 2015, the IIC's debt-to-equity ratio was at 100%, or one third of its potential. The IIC expansion will likely expand its lending base; however, public sector lending activities may

IN OTHER NEWS

company that qualifies as a REIT. Windstream said in a securities filing in 2014 that the move would save it $100 million a year in taxes by shifting about 11% of its annual revenue to the REIT through rent for use of the fixed assets.

MASTER LIMITED PARTNERSHIPS can be used to raise equity against portfolios of site leases for wind and solar projects and rooftop licenses for solar panels.

The conclusion follows from a private letter ruling the IRS released in December. The ruling is Private Letter Ruling 201549013.

Master limited partnerships, or MLPs, are large partnerships whose units are publicly traded. No taxes are collected at the entity level. Rather, earnings are taxed directly to the partners. MLPs can raise equity at higher multiples to earnings than corporations because there is no entity-level tax on the earnings. Investors also pay a liquidity premium for the ability trade the units in a public market.

An MLP can own sites, site leases and rooftop licenses.

The MLP described in the ruling planned to lease or sublease the sites to companies that own cellular towers, rooftop wireless and broadband internet installations, billboards, wind turbines and solar arrays.

The MLP said at least 85% of the rent received will be for use of the each site as opposed to rent for use of equipment put on the site. It said most of the rents will be fixed dollar amounts, but, in the case of sites used for billboards, they may be a percentage of gross receipts from advertisers reduced by some expenses. The expenses are agency fees or commissions paid by the lessee to a broker for finding advertisers, illumination charges, business license fees for the right to erect billboards on the site, continuity discounts, and non-income taxes paid in connection with billboards.

An MLP must have at least 90% good income each year to maintain status as an MLP. "Real property rent" is a form of / continued page 35

Development Banks

continued from page 33

decline. During a meeting of the IDB board of governors last year, one member country said that "if the IDB Group were to face a trade-off between lending to the public sector versus lending to the private sector, priority should be given to private sector lending," stressing that "current credit ratings of the IDB Group remains of utmost importance."

Given the gradual nature of the expansion of the IIC over the next decade, it is unlikely that the market will see a dramatic shift in the products and services the IIC offers. The IIC's new form contracts will create the most visible shifts in the market, as they will reflect new terms that merge the policies and practices of the former IDB and IIC groups. ◎

Central America: The Next Growth Market?

by Diego Gallegos, in Washington

Investment in South America is drying up as demand for commodities weakens, but because Central America is a commodity importer rather than exporter, its prospects look increasingly promising.

A new US $750 million aid package and a separate "Clean Energy Facility" will catalyze opportunities for investors in energy and infrastructure projects.

A slowdown in Asian economies upended a long-running bull market in commodities. The decline on commodity markets has reverberated noticeably in South America, where countries rode the commodity boom to impressive levels of growth. Now many South American countries, including Brazil, Chile and Venezuela, are experiencing the effects of this decline.

The commodity boom brought major opportunities for infrastructure and energy deals. Mining, energy, and oil and gas projects took off in places like Chile, Peru, Brazil and Colombia. However, as the boom recedes and investments in these areas dry up, investors will be looking for opportunities elsewhere.

Central American economies, unlike their South American counterparts, are not commodity driven and, as importers, they benefit from low oil and raw material prices. Furthermore, while South America became dependent on China's growth and its thirst for natural resources, Central America's fate continued to be linked to the United States' economy. This might not have been a solid proposition in 2009 and 2010, but today, as the US economy shows encouraging signs of recovery, Central America is benefiting from such growth. In fact, according to the World Bank's Global Economic Prospects, Central American economies are expected to grow faster than South American ones through 2018.

For infrastructure and energy projects, Central America is full of opportunities for investors. Multilateral agencies, foreign governments and the countries themselves have zeroed in on the region's infrastructure deficiencies as the main challenge to the region's economic competitiveness. The improving economic fundamentals and increased interest by foreign governments and multilateral agencies in Central America will boost development of roads, airports, power plants, power distribution lines, natural gas pipelines and LNG terminals. Projects in the region already include important infrastructure investments such as

Falling oil and raw materials prices are helping Central America as a commodity importer.

the $5.2 billion expansion of the Panama Canal, the $1.6 billion Mexico-Guatemala-Honduras natural gas pipeline, and the $1 billion Costa Rica-Moin container terminal.

Two sources of US government funding should serve as a catalyst to an already booming infrastructure and energy sector. One is a $750 million dollar aid package that the US Congress approved in December for Guatemala, El Salvador and Honduras. The other is the Clean Energy Finance Facility for the Caribbean and Central America run by the US Agency for International Development (USAID).

New US Aid Package

The $750 million aid package is an attempt to improve economic conditions in Guatemala, El Salvador and Honduras to reduce immigration into the US from the region.

The funding will be managed by the US Department of State and distributed to agencies such as USAID and the Inter-American Development Bank (IDB). The funds are expected to advance the goals of the Alliance for Prosperity in the Northern Triangle, an IDB program created to stimulate economic growth, reduce inequality, promote educational opportunities, target criminal networks responsible for human trafficking, and help create governance and institutions in the three countries. The program emphasizes the importance of improving economic development and competitiveness by lessening dependency on fossil fuels for power generation and improving infrastructure and logistics corridors.

USAID will use its share of funding to make grants. The IDB will provide loans to support country strategies in each Northern Triangle country.

Guatemala, El Salvador and Honduras are burdened with the most expensive electricity in Latin America as a consequence of their dependency on fossil fuels for power generation. In 2014, 46% of electricity in these countries was generated using fossil fuels. The Obama administration, the IDB and the countries themselves have identified this dependency as a major issue to be tackled by the aid package, which creates opportunities for various projects.

Four energy projects have been identified as a priority by the Alliance for Prosperity. All are government owned, but will create opportunities for other projects to be undertaken by the private sector.

One is doubling the capacity of the electricity grid in Central America (SIEPAC in Spanish) from its current 300-megawatt capacity to 600 megawatts. SIEPAC is a / *continued page 36*

IN OTHER NEWS

good income for an MLP. Real property rents cannot be tied to income or profits, but can be a fixed percentage or percentages of the lessee gross receipts. The rent must be for use of real property, but up to 15% can be for use of equipment leased in connection with the real property.

The ruling confirms that someone can amass a portfolio of site rights to put up renewable energy facilities, including rooftop solar, and monetize the future rents by raising equity against the projected rents in the public equity market.

Why not do the same thing with debt since debt is cheaper?

MLP equity may have a cost that is close to debt, but with equity, there is no obligation to repay a fixed amount by a fixed date. The equity investors take project and lessee credit risk. The ruling suggests that this may be easiest to do with bare sites or rooftops where the lessee is installing new assets. The rents should not be set at a level that is also rent for use of the equipment.

UNUSED TAX CREDITS that are being carried forward can be adjusted by both the taxpayer and the IRS, even after the statute of limitations has run on a tax audit, the IRS said.

The agency made the statement in a private letter ruling released in late November. The ruling is Private Letter Ruling 201548006.

The IRS normally has three years to audit a tax return. The three years run from the due date for the return or, if later, when the return was actually filed. Meanwhile, a taxpayer who wants to adjust what he claimed must do so by filing an amended return within three years after the original return was filed or, if later, two years after the tax was paid.

A company that owned restaurants failed to calculate correctly the amount of tax credits it was entitled to under section 45B of the US tax code for the employer share of social security and Medicare taxes it paid on employee tips over the period 1998 through 2012. The tax credit can be claimed in lieu of deducting the taxes.

/ *continued page 37*

Central America

continued from page 35

1,800-kilometer line consisting of 15 substations and 28 access bays running from Guatemala to Panama and facilitating a regional electricity market. Plans are also in place to extend the line to Mexico and Colombia.

The next priority is investment in national transmission lines to achieve the operational transmission capacity of 300 MW in SIEPAC which has not been achieved yet because of lack of improvements and reinforcements of national transmission lines.

The third project is construction of the Salina Cruz (Mexico)-to-Escuintla (Guatemala) natural gas pipeline.

The fourth project is construction of a regasification plant for importing natural gas as LNG into El Salvador, Guatemala and Honduras.

Table 1. INFRASTRUCTURE INVESTMENTS

CORRIDOR	REQUIRED INVESTMENT
1. Pacific corridor joining Mexico with Central America on the west coast of the region	Improvement of El Amatillo, Gausaule and La Hachadura border crossings and rehabilitation and road widening in El Salvador and Honduras
2. Bioceanico corridor between Quetzal port, Guatemala City and Barrios/Santo Tomas de Castilla ports	Improvement of ports, CA-9 road widening, improvement of rural roads, suburban ring and La Aurora International Airport.
3. The Acajutla corridor - San Salvaor - San Pedro Sula - Puerto Cortes	Improvement of El Poy border crossing, logistics and freight areas in Cortes port, Acajutla port and San Pedro Sula; rehabilitation of roads CA-4, CA-8 and CA-13 including bridges, improvement of tertiary road and urban areas, and construction of a load terminal at the San Salvador and San Pedro Sula airports.
4. El Ramal San Salvador - Bioceanico corridor	Improvement of the Anguiatu - La Ermita border crossing, rehabilitation of the road and improvement of rural roads in the corridor, upgrade of cargo handling at the El Salvador International Airport.
5. Quetzal Port corridor - Guatemala City - San Pedro Sula	Upgrade in the border crossing El Florido, rehabilitation of roads CA-11, CA-4 and 500 km of the tertiary road, improvement of cargo handling in the urban area of Guatemala City and La Aurora Airport, internationalization of the Puerto de San José Airport and road connection.
6. Acajutla Port corridor - San Salvador - Tegucigalpa	Rehabilitation of roads CA-5, CA-1 and CA-8, tertiary road, and bypasses of urban centers, and improvement of border crossing El Amatillo.
7. Atlantic corridor between Managua, Tegucigalpa and Cortes port	Improvement Las Manos border crossing, rehabilitation of roads CA-11, CA-15, CA-6 and CA-5, in the urban areas of Tegucigalpa and San Pedro Sula, rehabilitation of rural roads and improvement of Managua and San Pedro Sula International Airports
8. Atlantic corridor between Belize and the Bioceanico corridor	Improvement of the Melchor Mencos - Benque Viejo border crossing, the Belize City port, rehabilitation of George Price Highway and CA-13 Highway, improvement of rural roads, upgrade of the cargo terminal at the Phillip Goldson Airport.

On the infrastructure side, the Alliance for Prosperity is focused on eight logistics corridors based on their potential to facilitate trade and economic activity among the countries. Table 1 shows the eight projects.

Clean Energy Facility

Another potential source of interest for investors interested in renewable energy projects in the region is the financing available under the USAID Clean Energy Facility for the Caribbean and Central America. This is a $20 million dollar facility supported by four US government agencies: the Department of State, USAID, the US Trade and Development Agency (USTDA) and the Overseas Private Investment Corporation (OPIC). It functions as a grant facility when support is provided by USTDA and USAID, and a loan or loan guarantee support when support is provided by OPIC.

The facility was launched in 2015 and is available for two years. Its aim is to provide early-stage financial assistance to clean energy projects in Central America and the Caribbean.

Grant and loan funding is available for project developers and host country public- and

chadbourne

Eight major infrastructure projects should serve as a catalyst for further development.

private-sector project sponsors for clean and renewable energy projects in power generation, sales and distribution of small-scale clean energy systems and products that provide access, or extend the hours of access, to electricity and renewable energy infrastructure catalyzers such as financing and leasing facilities.

The funds can be used for early-stage costs such as engineering costs associated with project design, technology assessment and overall feasibility studies, legal costs for preparation of documentation related to permitting, power purchase, EPC, O&M and financing agreements, consulting costs for the preparation of environmental and social impact studies and third-party costs associated with physical and technical analysis of renewable energy resources.

To qualify for funding, the project must have clear social and economic benefits, with processes in place to monitor and evaluate these benefits, a positive impact on energy access, security, poverty alleviation, gender inclusion and consistency with the USAID program in the country where the project is located, and support low emissions development in Central America and the Caribbean.

The maximum grant available for a single project is $1 million (in the case of USAID grants), so long as the amounts do not exceed 3.6% of the total project cost. USAID says that applications take approximately 90 days to process and that there is no associated filing fee.

IN OTHER NEWS

By the time the company discovered the error, the statute of limitations had closed on tax years before 2010. It amended its 2010 through 2012 tax returns and calculated the credits accurately on its 2013 return.

Had it calculated the credits accurately before 2010, then it would have been entitled to a larger credit carryforward into 2014.

The IRS said it can increase its tax credit carryforward, citing precedent involving the investment tax credit.

Most unused tax credits for businesses can be carried back one year and forward up to 20 years under section 39 of the US tax code.

A 1982 revenue ruling (Revenue Ruling 82-49) says that the investment tax credit does not have to have been claimed on a tax return, or in a timely claim for a refund for the year the asset went into service, before it can be carried forward to an open tax year.

The IRS said the same principle should apply to section 45B credits. "[I]t is clear that a general business credit originating from closed years and being carried into open years in arriving at tax due can be adjusted to correct errors under the applicable provisions of the law by both the Service and Taxpayer."

However, the full effects of the extra tax credit need to play through the tax return for the closed year so that the accurate amount of credit is carried forward. For example, if the extra credit would have been used to reduce the taxpayer's taxes in the closed year, then it cannot be carried forward.

A REFINED COAL TRANSACTION has landed in court after the IRS disallowed all the tax credits. Ecotec Coal, LLC filed suit in the US Tax Court in November to reverse an IRS disallowance of refined coal credits that the company has been carrying forward since 2006 and claiming a little at a time on its annual tax returns. The IRS disallowed $14.6 million in credits claimed in 2011. The company filed suit in 2013 to restore tax credits that were disallowed on its 2008, 2009 and 2010 tax returns. The 2013 case is still

/ continued page 39

Traps for the Unwary: PUHCA

by Caileen Gamache, in Washington

The Public Utility Holding Company Act — called PUHCA — is the "sleeper cell" of US energy regulations.

It was largely extinguished by Congress in 2005, but lingering provisions infiltrate deals and can tag unwary investors with unintentional regulatory status.

Anyone doing deals in the US gas and power sector should understand that a single improperly-structured investment can subject an entire corporate family to regulation by the Federal Energy Regulatory Commission as a utility holding company.

Investors who are not careful can end up being regulated as utility holding companies under PUHCA.

Four primary consequences flow from such regulation.

FERC may require prior authorization of transactions, leading to inopportune closing delays. Implicated entities must comply with onerous book and recordkeeping requirements. There can be sanctions and negative public relations fallout associated with PUHCA violations. FERC can also restrict corporate activities and impose compliance obligations.

Various tactics exist to deactivate PUHCA's power.

It Only Takes One

An investor may become subject to FERC regulation as a utility holding company if it takes ownership or control of 10% or more of the voting securities of an "electric utility company," a "gas utility company," or another utility holding company.

All it takes is one such investment to subject an entire group of affiliated companies to regulation.

Terminology is key under PUHCA.

An "electric utility company" includes any entity that owns or operates facilities for the generation or transmission of electricity for wholesale or retail sale.

A "gas utility company" includes entities that own or operate facilities used for retail distribution of gas for heat, light or power.

Any upstream entity that directly or indirectly holds the threshold interests in an electric or gas utility company is a "holding company."

Thereafter, as long as the relevant asset is on the books, the holding company and all of its subsidiaries will be labelled a "holding company system."

To put PUHCA into context, it is a Depression-era remnant that was initially enacted in 1935 in an age of powerful multi-state utility conglomerates and corruption. Congress wanted to prevent unregulated upstream owners of regulated utilities from using their market power to engage in price gouging of utility ratepayers, debt shielding and general money laundering. Times changed, and Congress repealed the original version of PUHCA in 2005, and replaced it with an abridged version that significantly limited the reach of the statute and reduced the burden on holding companies caught in its net.

Deal Delays

Busy executives often first learn of PUHCA when the commercial value of a transaction is threatened by delay.

FERC must review and approve or deny certain acquisitions in which a utility holding company plans directly or indirectly to acquire or merge with an electric utility company, an entity that transmits electricity, or another utility holding company.

If prior approval is required, then applicants should conservatively allow at least 180 days for FERC review before closing. Realistically, the average review period only lasts about 60 days

chadbourne

for uncontested applications. FERC may grant a request for a condensed review period for good cause, but in recent years its staff has indicated that "good cause" must involve more than routine commercial interests. FERC also has the power to extend the review period, which it typically reserves for controversial transactions.

If a deal closes without obtaining required approval, then from a regulatory perspective it is effectively void. Imagine the consequent chaos. Participants may also be subject to sanctions.

Prior approval by FERC is also required for certain "dispositions" of FERC-regulated public utilities, including transfers of utility assets and changes of control over the seller. A FERC-regulated public utility is any company that owns or operates facilities used to make wholesale sales of power or to transmit power in interstate commerce.

Thus, review could be required even if a corporate family is seeking to sell, rather than acquire, utility interests. It can also apply to a seller in a transaction even if it does not apply to the buyer. There are several exemptions and blanket authorizations that might eliminate this burden.

In sum, whether FERC prior approval will actually be required for a transaction can be nuanced, and any transaction involving the transfer of interests in energy entities or assets should be evaluated with PUHCA in mind.

Books and Records

Any utility holding company subject to FERC regulation must record, maintain, retain and grant FERC access to any books, accounting statements, and other records that FERC deems relevant to the jurisdictional price of gas or energy sold by public utilities and natural gas companies or otherwise pertaining to the protection of the customers of such entities.

This requirement extends not only to the holding company, but also its affiliates.

FERC's reach transcends US boundaries to foreign affiliates.

The books and records subject to review must be maintained and retained pursuant to a detailed uniform system of accounts in some circumstances.

State regulators also have review authority over the books and records of utility holding companies and their affiliates under PUHCA. A state may pry to the extent it considers the records relevant to the rates a utility doing business in the state charges for electricity or gas or for any other reason considered necessary to discharge its regulatory duties effectively.

/ continued page 40

IN OTHER NEWS

pending. The latest suit focuses on 2011.

The company says in the latest suit that the government should have the burden of proving that it is not entitled to the tax credits after FBI and IRS agents raided the company offices in October 2012 and took all the company records as part of a criminal investigation that led to a plea deal by the CEO in May 2015. The CEO, Stephen Parks, pled guilty to a charge of selling fictitious refined coal credits though a separate company called Global Coal, LLC. Parks was sentenced to 27 months in federal prison, to be followed by three years of supervised release, and ordered to pay $845,000 in restitution to the IRS (the amount of the tax credits he admitted having fraudulently sold) and forfeit approximately $7.5 million in property.

Ecotec Coal says it produced enough refined coal in 2006 to claim $118.6 million in tax credits initially using a prototype "bio-refinery machine" mounted on a three-axle trailer that applied water and a protein enzyme to coal to make it less polluting. The prototype had capacity to treat two tons an hour. The company says it eventually also used a larger machine with a nameplate capacity of 70 tons an hour, but an actual output of 40 to 50 tons an hour, in December 2006. It says it treated 20.9 million tons of coal that were sold to an affiliated company.

The US government allows tax credits of $6.71 a ton to be claimed by anyone who modifies coal to make it less polluting and then sells the coal to a third party for use in a power plant or factory to make steam. (The figure $6.71 is the tax credit for 2015. The amount is adjusted each year for inflation.) The tax credits can be claimed for 10 years after the machinery used to treat the coal is first put in service. Such machinery had to be in service by December 2011 for the output to qualify.

HEDGES are being used to increase leverage in renewable energy financings by protecting against volatility in revenue due to fluctuating wind velocity, solar insolation or weather.

/ continued page 41

PUHCA Traps

continued from page 39

Penalties

Anyone violating PUHCA can be subject to penalties of up to $1 million per violation per day, plus be required to disgorge any improper profit.

Executives involved in such violations may also be referred to the Department of Justice for criminal prosecution and can be sent to prison.

Candidly, neither criminal nor significant civil penalties are likely. Perhaps of greater concern is the potential for damage to corporate reputation. Although average consumers are unlikely to know about PUHCA, they understand when a company is alleged to have violated a federal law designed to protect consumers. The scandal is extra spicy when it involves energy interests and consolidated wealth, regardless of how mundane the actual violation or regulation at issue.

Some acquisitions can require FERC review lasting as long as 180 days on account of PUHCA issues.

In egregious circumstances, there is a risk that FERC may limit a company's ability to engage in regulated activities. This could significantly affect a corporate revenue stream and lead to devaluation of expensive assets. Rarely will a PUHCA-related violation be a company's only regulatory violation, particularly if the entity became regulated unwittingly. The discovery of regulatory violations is routinely followed by an obligation to adopt expensive corporate compliance programs and submit to periodic regulatory audits or reporting requirements. The variety and unpredictability of possible repercussions for PUHCA-related violations underscores the importance of prevention.

Mitigation Strategies

The most common strategy to avoid running afoul of PUHCA is to restrict the type of energy assets within a corporate portfolio.

Broad PUHCA exemptions can automatically spare investors if they invest in a company or project considered a qualifying facility (QF), exempt wholesale generator (EWG), or foreign utility company (FUCO).

A QF is a small power project that uses renewable energy or waste as fuel or a cogeneration facility that produces two useful forms of energy from a single fuel and satisfies certain other FERC requirements.

An EWG is a company that is engaged directly or indirectly and exclusively in the business of owning or operating eligible generating facilities and selling the electricity at wholesale.

A FUCO is either an electric or gas utility company located outside the US, that does not derive income from utility activities within the US, and does not have any subsidiary public utility companies within the US.

A holding company that only owns QFs, EWGs and FUCOs is usually excused from having to obtain prior authorization from FERC to acquire interests in other QFs, EWGs and FUCOs.

Other holding companies and transactions frequently qualify for PUHCA exemptions or waivers if FERC finds that the books and records of such entity or class of transactions poses little or no risk to jurisdictional rates or utility consumers. Common examples include purely passive investments by investors like mutual funds in utility companies, single-state holding companies that derive no more than 13% of their revenues from utility activities outside a single state, and holding companies of electric utility companies no greater than 100 MW in aggregate size used primarily to self-serve its own or affiliates' loads. An important — and frequently misunderstood — caveat to these routine waivers and exemptions is that they only apply if the holding company makes certain FERC filings. ◎

Environmental Update

A new law enacted in December should streamline should environmental review and permitting of large infrastructure projects. The new law is called the "Fixing America's Surface Transportation Act" or "FAST Act."

It requires federal agencies to set performance schedules, creates a new interagency council to accelerate reviews where multiple agencies are involved, and limits the time opponents have to appeal agency decisions, including under the National Environmental Policy Act.

The FAST Act is a transportation statute, but the parts of it that streamline environmental review apply broadly to power plants, transmission lines, roads, rails, aviation, ports and waterways, water resource projects, broadband, pipelines, manufacturing or any other qualifying sector as determined by the new interagency council, the Federal Permitting Improvement Council.

To qualify for streamlined review, the project must require federal action like a federal grant or loan guarantee or use of federal land so that it is subject to the NEPA review process, and it must be expected to cost more than $200 million. The developer should submit a notice to the council and the lead permitting agency summarizing the project and explaining how the project qualifies as a covered project under the Fast Act.

The council is supposed to come up with an inventory of projects that are currently in the queue awaiting environmental reviews by May and then develop recommended environmental review schedules for project categories by December 2016.

In general, a final decision by an agency within any category must be issued 180 days after a complete application is received with all the information required for review and after the agency has held any required public hearing.

An online "permitting dashboard" will be maintained so that applicants can more easily track the status of permitting reviews for their projects.

The FAST Act makes it harder to challenge federal permitting decisions. First, there will now be a two-year statute of limitations on NEPA challenges as opposed to six years. Second, anyone seeking judicial review of an agency decision under NEPA must have submitted comments during the agency's review period that are detailed enough to put the agency on notice of the issue. Finally, in deciding whether to issue injunctive relief, courts must consider not only the potential effects */ continued page 42*

The hedges are most common in wind financings, but at least one hedge was done in 2015 for a solar project.

They have terms of three months to 10 years and are usually structured as swaps, but may also take the form of insurance. They may also cover penalties under power contracts or for participants in organized markets like PJM.

Output from wind and solar projects is less predictable the shorter the measuring period. For example, output from projects in west Texas can vary as much as 20% above or below the long-term average for wind farms and 10% for solar projects when looking at annual data, but 30% for wind and 15% for solar if quarterly data is used.

MINOR MEMOS. There is speculation that new partnership tax audit rules in the United States may be the last straw that causes more US states to start imposing an entity-level tax on partnerships as Texas and Tennessee have already done. This could be an issue for lenders. Banks lending to finance projects owned by partnerships calculate debt service coverage ratios on a pre-tax basis when sizing the debt . . . . UBS says that a number of utility-scale solar projects are being delayed to 2018 as there is no longer a need to complete the projects in 2016 to qualify for federal tax credits. It says this will allow the developers to avoid a "merchant nose" under power purchase agreements with California utilities that do not kick in until 2018 and that margins on the projects might improve by 3% to 4% as projects that delay construction will benefit from falling equipment costs . . . . Moody's says it expects $50 billion in green bonds to be issued in 2016, with a lot of the activity expected in China. Green bond volume was $42.4 billion in 2014. There were 105 issuers and 197 transactions. About 40% of the issuers were financial institutions. Green bonds are bonds whose proceeds will be used in ways that help reduce global warming . . . . US installed wind capacity stood at 74,472 megawatts at the end of 2015. Solar capacity was a little over 25,000 megawatts.

— contributed by Keith Martin in Washington

Environmental Update

continued from page 41

on public health, safety and the environment, but also the potential for significant negative effects on jobs.

Northern Long-Eared Bat

The US Fish and Wildlife Service issued final rules in January to protect the northern long-eared bat under the Endangered Species Act. The bat is found in 37 states and has been in marked decline due to a fungal disease called white nose syndrome. It was listed as "threatened" last April.

Under federal environmental law, bat species are not afforded legal protection unless covered under the federal Endangered Species Act. That statute makes it unlawful to "take," meaning harm, harass or kill, any federally-endangered or threatened species.

"Incidental takes" may be permitted.

Importantly for developers, the final rule broadened the circumstances where "incidental takes" will be allowed beyond those that were originally proposed. The original list focused on forest management. Going forward, unintentional harm occurring during the normal course of work will be exempted, except in limited circumstances. This includes harm caused by land clearing, building of roads and construction of pipelines, wind farms or electric transmission lines.

The final rules focus on where and when the bats are most vulnerable by imposing narrowly tailored prohibitions on tree cutting in a broad range of locations for two months each year and year round in more limited areas. Specifically, for sites where bats are infected with white nose syndrome, tree removal will be barred year round within a quarter mile of any known bat hibernation sites, called hibernacula. Bats usually hibernate in caves or mines. Tree removal will also be barred within 150 feet of any known maternity roosting trees during the two-month pup-rearing season in June and July throughout the entire area where the disease is found.

The long-eared bat is found 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 effects bats in up to 28 states, with particular devastation in the northeast.

If white-nose syndrome continues to cause the species to decline, then the Fish and Wildlife Service could list the species as "endangered" rather than "threatened." This would mean that most incidental takes of the bats would be barred unless a permit has been issued.

Eagles

The Obama administration has given up trying to restore the ability of the US Fish and Wildlife Service to issue long-term permits to "take" bald and golden eagles through the courts. Permits as long as 30 years had been available to wind farms to shield such projects from prosecution when they unintentionally kill or otherwise disturb eagles or their habitats. The permits will now revert to five years.

A US district court held last August that the Fish and Wildlife Service failed to conduct a full environmental review before lengthening the duration of such take permits from five to 30 years.

Fish and Wildlife argued that a full review is not required in cases of an "administrative, financial, legal, technical or procedural nature" or "whose environmental effects are too broad, speculative or conjectural to lend themselves to meaningful analysis." The court said these exemptions apply only where there is an insignificant or minor effect on the environment.

Environmental groups and Indian tribes sued the Fish and Wildlife Service to block the longer permits.

The agency is now going through the full environmental review rather than continue to argue the point in court. The market is still sorting out whether it will settle for five-year permits in the interim, given that a five-year permit is all that is on offer and the market made do with them before 2013, or whether certain projects may be delayed until the window reopens for longer permits.

Even while Fish and Wildlife was offering permits for up to 30 years, the permits still required operational reviews every five years by the agency. However, the reviews were not the same as having to apply for a new permit. Fish and Wildlife also reserved the right with the longer permits to modify or revoke a permit if issues arise, and ongoing monitoring for mitigation effectiveness was still required.

Clean Power Plan Litigation

Opponents of the Clean Power Plan failed in late January to persuade a US appeals court to freeze implementation of the plan while the court considers whether the Obama administration had authority to impose the plan.

Twenty-nine US states had asked the court to "stay" implementation of the plan while the merits of the plan are being argued in court. The states have now appealed the decision on the stay to the US Supreme Court.

The Clean Power Plan requires a 32% reduction in carbon dioxide emissions from most existing coal- and gas-fired power plants by 2030. Each state has been assigned individual carbon reductions. Each must submit an implementation plan by September 6 this year. The federal government will impose a federal plan in states that fail to submit their own plans or that submit plans that fall short of what the Clean Power Plan requires. States must start to show carbon emissions reductions by 2022. States may ask for up to another two years to submit their own plans before the federal government will step in.

A decision on the merits in lawsuits by 29 states to block implementation of the Clean Power Plan could come as early as late summer.

The US appeals court that turned down the stay said only that the opponents of the plan had "not satisfied the stringent requirements for a stay pending court review." The opponents had alleged immediate and irreparable harm resulting from the need to close coal-fired power plants and overhaul the power sector and from the extraordinary burdens placed on state governments to devise compliance plans by the September 6 deadline.

Instead of a stay, the US appeals court set an aggressive schedule for briefing and oral argument on the merits. Final briefs are due by April 22 and oral arguments will be held on June 2. The opponents of the plan have asked that a final decision be issued before states are required to turn in their implementation plans on September 6.

Wind and Solar Incentives

Renewable energy groups are urging the US Environmental Protection Agency to move up the start of a window period for wind and solar projects to qualify for allowances and emissions rate credits under a "clean energy incentive program" that is part of the Clean Power Plan.

The clean energy incentive program –- called CEIP –- offers carbon dioxide allowances and emissions rate credits to new wind and solar projects based on their electricity output during 2020 and 2021.

New wind and solar projects that commence construction or operation after a state submits its final implementation plan to EPA would be entitled to receive them. The allowances and emissions rate credits will have value and can be sold in an emissions trading market.

Many states are expected to file only initial plans in September 2016 and to request a two-year extension for filing a final plan. Renewable energy groups worry that this will deny the benefit to projects that get underway before September 2018.

They want all projects that commence construction or operation after September 6, 2016 to qualify rather than limiting allowances and credits to projects that commence after a state submits its final implementation plan.

Having a fixed eligibility date for all projects would make any stimulus to wind and solar from the CEIP incentives coincide more closely to the stimulus the newly-extended renewable energy tax credits are providing. The idea is to give a final push through tax and CEIP incentives until the Clean Power Plan starts having an effect.

Both the wind and solar trade associations expressed concern that the way the CEIP is currently proposed to operate could cause some developers to delay work on projects until late 2018 to qualify.

/ *continued page 44*

Environmental Update

continued from page 52

MACT Rule

A US appeals court sent an EPA rule requiring power plants to use "maximum achievable control technology" to reduce air toxics emissions back to the agency for further work rather than throw out the rule and require the agency to start over as opponents had hoped. The court rendered its decision in December.

EPA will basically be required to perform only a cost analysis of the rule as part of its statutorily-required finding that the rule is "appropriate and necessary."

The US Supreme Court told the agency in a case called Michigan v. EPA in June 2015 that it should take compliance costs into account at the outset of any rulemaking under the section of the Clean Air Act on which the MACT rule is based.

The agency has already issued a proposed cost analysis for public comment and indicated that it anticipates issuing a final finding by April 15, 2016. The opponents of the MACT rule say the proposed finding is procedurally flawed and unlawful and are probably headed back to the appeals court. They face an uphill battle in any such appeal. ◎

— contributed by Andrew Skroback and Richard Waddington in Washington

Project Finance NewsWire
is an information source only. Readers should not act upon information in this publication without consulting counsel. The material in this publication may be reproduced, in whole or in part, with acknowledgment of its source and copyright. For further information, complimentary copies or changes of address, please contact our editor, Keith Martin, in Washington (kmartin@chadbourne.com).

Chadbourne & Parke LLP

chadbourne.com

New York
1301 Avenue of the Americas
New York, NY 10019
+1 (212) 408-5100

Washington, DC
1200 New Hampshire Avenue, NW
Washington, DC 20036
+1 (202) 974-5600

Los Angeles
350 South Grand Avenue, 32nd Floor
Los Angeles, CA 90071
+1 (213) 892-1000

Mexico City
Chadbourne & Parke SC
Paseo de Tamarindos, No. 400-B Piso 22
Col. Bosques de las Lomas
05120 México, D.F., México
+ 52 (55) 3000-0600

São Paulo
Av. Pres. Juscelino Kubitschek, 1726
16° andar
São Paulo, SP 04543-000, Brazil
+55 (11) 3372-0000

London
Chadbourne & Parke (London) LLP
Regis House, 45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000

Moscow
Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow 115054 Russian Federation
+7 (495) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

Warsaw
Chadbourne & Parke
Radzikowski, Szubielska i Wspólnicy sp.k.
ul. Emilii Plater 53
00-113 Warsaw, Poland
+48 (22) 520-5000

Istanbul
Chadbourne & Parke
Apa Giz Plaza
34330 Levent, Istanbul, Turkey
+90 (212) 386-1300

Dubai
Chadbourne & Parke LLC
Boulevard Plaza Tower 1, Level 20
PO Box 23927, Burj Khalifa District
Dubai, United Arab Emirates
+971 (4) 422-7088

Johannesburg
Katherine & West
114 West Street
Sandton, Johannesburg
South Africa
+27 (087) 980-1340

01-01 PF NewsWire February 2016