CHADBOURNE
& PARKE LLP

PROJECT FINANCE

NewsWire

September 2012

Survival Strategies: The Challenges In Utility-Scale Renewable Energy

The US put incentives in place in 1978 after the Arab oil embargo to encourage more use of renewable energy. They were allowed to lapse in 1985. The incentives were restored in 1992 and increased in the last decade, but they are now in danger of lapsing or being shed in an effort to reduce corporate tax rates at a time when low natural gas prices and slow load growth are already taking a toll on renewable energy developers. What is a survival strategy during such periods?

Four senior executives of renewable energy companies shared their thoughts at the Chadbourne 23rd annual global energy and finance conference in Stowe, Vermont in late June. The four are Martin Mugica, executive vice president of Iberdrola Renewables, Paul Gaynor, CEO of First Wind, Robert Mancini, CEO of Cogentrix Energy, and Michael Storch, executive vice president and chief commercial officer of Enel North America. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Martin Mugica, Iberdrola came to the United States to do wind projects. What is it doing today?

MR. MUGICA: We started diversifying last year into solar. Right now we have 50 megawatts of solar facilities in operation: 30 megawatts in Colorado and 20 megawatts in Arizona. We have been interested from the start in / continued page 2

IN OTHER NEWS

A POWER CONTRACT ruling is withdrawn.

The Internal Revenue Service notified the taxpayer that it is withdrawing a private ruling it issued earlier this year that said a company buying an operating wind farm did not have to allocate part of the purchase price to a long-term power contract that came with the project. The power contract required the electricity sold under it come from the particular wind farm. The ruling analogized the situation to where someone buys a building in which tenants have leased office space. Part of the purchase price does not have to be allocated to the leases. Instead, the building comes subject to the leases; the leases are a burden on ownership. The purchase price is treated as a cost of the building. / continued page 3

IN THIS ISSUE

Survival Strategies

continued from page 1

biomass, and of course we have a lot of wind. We are open to other opportunities, but at this point this is what we have in our portfolio.

MR. MARTIN: Paul Gaynor your company is called First Wind. Will we see a name change in the future? (Laughter.)

MR. GAYNOR: Everybody keeps asking that. We have 1,000 megawatts of operating wind farms. We have done 1,200 megawatts of transmission assets, all on the back of our existing portfolio. We have done two large battery projects. We are working on a solar project, but what I call related solar that is adjacent to one of our wind facilities, and we are working on a natural gas play in the Pacific Northwest again on the back of our wind business infrastructure that we already have.

Returns for solar and wind developers on US projects are in the high single digits.

MR. MARTIN: Bob Mancini, Cogentrix was originally a developer of coal-fired power plants and then Goldman Sachs bought it, and the company has changed its focus. What is the focus now?

MR. MANCINI: Cogentrix was a developer of conventional thermal power plants, both coal and natural gas. We started to venture into renewables in 2008, but solely in solar. We do not develop any wind. There was a group within Goldman Sachs at one time, Horizon, that was another team that developed wind, but that was separate from Cogentrix. We made our first play by buying 43 megawatts of the SEGS facilities in California. We sell our power to Southern California Edison under a long-term contract. The next year, in 2009, we started developing a large concentrated photovoltaic power plant. It is 30 megawatts. It went commercial a couple months ago and, I believe, is the largest CPV project in the world at this time. We are working on a 150-megawatt project in the Imperial Valley that uses more conventional photovoltaic technology. I don't think we will see another CPV project in this country any time soon given how low panel prices are.

MR. MARTIN: Mike Storch, Enel acquired hydro projects and developed wind when it first came to the US. What is it doing today?

MR. STORCH: Enel Green Power is the only Enel company currently active in North America, and it does all renewables. We have solar, hydro, wind, geothermal and biomass projects in operation, and we are also starting to combine technologies. We recently dedicated the first combined geothermal and solar PV facility in the world as far as we know.

MR. MARTIN: Are you shifting developers from wind to the other types of projects you mentioned?

MR. STORCH: There is a shift, mostly toward solar, because of what is happening on the tax side. We have the next three or four years to get some solar done and still benefit from the tax subsidies for solar.

MR. MARTIN: The production tax credit may run out for wind at the end of this year. If it does, will it be a case — if one thinks of the wind industry like a large plant — of the water being cut off before the plant can truly take root?

MR. MUGICA: I think the position of the wind industry in the US is pretty material, so the plant is of some size already. The problem is there is a danger of the plant withering and parts of it dying under current weather conditions: low natural gas prices, transmission constraints, low load growth and inability to get utilities to enter into long-term power contracts. If we were facing healthier market conditions, we could probably live without production tax credits. Wind has a future in a normal market.

Good Time for Acquisitions?

MR. MARTIN: I met with a CEO of a wind company at the Global Windpower 2012 convention in Atlanta last week who has raised a fund to buy operating wind farms. He said he hears so many complicated business plans, but his business plan is simple. The market is depressed. Wind assets are cheap. He thinks the market will recover by 2015. "I buy low and sell high," he said. Paul Gaynor, do you see a recovery by 2015?

MR. GAYNOR: Yes. It is an opportune time to look at acquisitions. We have three of what I call little acquisitions. Ironically, we are sitting today on a large pile of cash that it makes sense to try to deploy by buying projects. Temporary production tax credits make this a difficult business to manage. This will get me into trouble with my colleagues, many of whom are in the audience, but I think the best thing that could happen to the wind industry, frankly, is if the PTC went away. It is absolutely brutal to manage this business year to year when you don't know what is going to happen. We are incredibly busy this year and, on January 1, 2013, we will have nothing in the pipeline. That is the challenge.

That is why we are looking at solar. That is why we are keeping busy with transmission lines. Even as a wind company, we have never covered the entire US. We have been focused on a handful of states with strong renewable portfolio standards: the New England states, New York and, to a certain extent, California and Hawaii. Those are some places that we might still be able to transact without a PTC because a higher price for renewable energy credits has the potential to make up some of the lost revenues from the PTC.

MR. MARTIN: I read this morning that Riverstone Holdings, which owns Pattern or a large stake in Pattern, is now putting its stake in that company up for sale. Is this a good time for people to be exiting the business if prices are depressed? It seems to be a good time to be a buyer rather than a seller, no?

MR. STORCH: It depends on what you are selling. Contracted operating assets remain very attractive. People will look at a pipeline of development projects that still needs to be contracted for power sales and built as a liability rather than an asset. There are selected opportunities. We are seeing wind projects today that are economic with production tax credits and power prices in the low \$30-per-mWh range on a levelized basis. Losing the PTC increases the amount of revenue needed over a 20-year power contract by more than \$20 a mWh. So a project with a power contract that pays \$55 mWh in an area with a high capacity factor can be competitive without tax credits. Continuing improvements in technology can only make things better.

MR. MARTIN: So in that sense, the PTC has served its purpose, or at least helped, by helping the industry to reach scale: inducing efficiencies and bringing down cost to the point where you can compete at current market prices.

MR. STORCH: Yes with projects in places like Kansas and Oklahoma with really robust wind resources, but part of the challenge is the load is not there / continued page 4

IN OTHER NEWS

An IRS branch chief said last April shortly after the PPA ruling was made public: "We have a saying [at the IRS] that you know you issued a bad ruling if 70 people ask you for a copy the next day."

Before the ruling, most companies would have allocated value to the power contract to the extent it is "in the money," meaning the contact entitles the holder to a higher electricity price than he can fetch currently in the market.

CALIFORNIA explained further in early September in what circumstances it will treat the transfer of an interest in a solar project as a trigger to start collecting property taxes on the project.

Solar generating equipment is effectively exempted from annual property taxes in California, but it becomes subject to such taxes if there is a sale of the project or change in control of the project company that owns the project after construction. Property tax rates vary by county. They can be as high as 2% of assessed value.

The State Board of Equalization proposed revisions to the property tax assessor's manual and released a separate opinion letter on September 5 in response to questions from solar companies.

The assessor's manual would say the following.

The sale of a solar project or an interest in the company that owns the project during construction will not trigger property taxes. Entering into a tax equity transaction structured as a sale-leaseback within three months after the project is first placed in service or a partnership flip will not trigger property taxes. There is no deadline to enter into the partnership flip transaction. (An inverted lease does not trigger property taxes because it is not a sale of the project.)

However, property taxes will be triggered when a developer who has sold and leased back his project exercises an option to repurchase the project. There is a risk that the "flip" in a partnership flip transaction will trigger such taxes. However, a board official / continued page 5

Survival Strategies

continued from page 3

— it is in the big population centers elsewhere — and there are not the transmission lines to move the electricity. A lot of the low-hanging projects that work with power prices in the $30-per-mWh range have already been developed.

MR. MARTIN: Do you share Paul Gaynor's view that it would probably be better for the industry if the PTC were not extended?

MR. STORCH: What would be best for the industry in my personal opinion is a five- or 10-year extension of the PTC that ratably phases out to zero at the end of this period so that people can plan. A one-year extension in a lame duck session of Congress in December is almost worthless except for a handful of projects. The industry is dead in the water for now after 2012 and will likely stay dormant for at least a couple of years without some kind of PTC extension. Maybe there will be a couple projects that will benefit in the first quarter of 2013 because they failed to achieve commercial operation at the end of this year. Maybe a few projects with long-term power contracts will be able to make something happen, but a one-year extension would not bring back the turbine manufacturers' operations to full scale.

Returns in the US Market

MR. MARTIN: Let the record show that when Mike Storch mentioned a one-year extension, Martin Mugica waved his hand dismissively.

Let me test a proposition. We had a large Spanish solar company come through our offices a few weeks ago that is keenly interested in Latin America and Africa for utility-scale solar development, but not so much in the United States. The company does not believe the returns justify large solar projects in the United States, even with a 30% investment tax credit. Bob Mancini and the rest of you who are moving some of your resources into solar, is the Spanish company right or, if not, what does it have wrong?

MR. MANCINI: I think the company is right. The Chinese panel manufacturers have a severe overcapacity problem and have been bidding into utility tenders as a way of finding outlets for their panels. This has pushed down returns to a point where developers are better off looking at other markets. Capital finds the market with the best balance of risk to reward. However, the issue in many emerging markets is lack of infrastructure to support development. There are better opportunities still in the solar sector in places like Germany, parts of India and probably Brazil than in places like Africa where there is not the infrastructure to support utility-scale transmission.

MR. MARTIN: Does anybody else disagree with the Spanish assessment?

MR. GAYNOR: We are focused on markets that are short on renewable electricity. The New England states, California and Hawaii all places that are desperately short. For example, there is only one wind farm in Vermont.

MR. MARTIN: It is a First Wind project. Can we see it from here?

MR. GAYNOR: You would have to get up on top of a mountain with binoculars. It took us six years to develop. The New England states have 750 megawatts of wind farms in operation or under construction, and they need to get to 4,000 to 5,000 megawatts by 2020. It is a great opportunity. There is a better ratio of risk to return here than some place south of the border.

MR. MARTIN: You are still bullish on those parts of the US that have high renewable portfolio targets that have not been met. Martin Mugica?

MR. MUGICA: I got a lot push back from our parent company when I started promoting two solar projects in 2010 because of the experience with solar in Spain. It took a lot of time to convince our parent that these were good projects with sound long-term power contracts. We are looking to do more solar in the US. Our experience in other countries like Brazil and Mexico has also been good. The problem in Mexico is that you have in almost all the cases just one customer: the Comisión Federal de Electricidad. Brazil is a very complicated country politically. You really need to have good partners and contacts to be successful and, then, you know how it is currently in Europe. We came to the United States in 2006. Right now we have 5,500 megawatts of operating projects. I do not see any other country in the world that can give you that kind of opportunity.

MR. MARTIN: So there is an alternative Spanish view that is still bullish on the US market.

Bob Mancini, let's drill down into something that you said. Solar panel manufacturers are competing with developers in utility solicitations to supply electricity. Some manufacturers have acquired smaller solar developers so that they are vertically integrated. Is this making it impossible for true developers to operate?

MR. MANCINI: It is making it difficult for those of us who are looking for reasonable returns to compete. It is not a level playing field. The Chinese panels are heavily subsidized. The tariffs that the US is moving to impose on Chinese-made solar cells are starting to have an effect. The Chinese are backing away from some projects that they were pursuing earlier. The Chinese panels will find other markets. The US margins are still too thin to reward us to take the risk. Part of the resolution will be to deploy some of the excess capacity in China. That would go a long way to change some of the current market dynamics.

MR. MARTIN: Mike Storch, what are current rates of return for utility-scale solar projects?

MR. STORCH: Solar is generally at the low end of the range. We are seeing market returns in the 7% range, perhaps a little better, but not much. Returns for wind projects are generally 8 1/2% to 10% except in especially competitive markets. These are unleveraged after-tax returns assuming tax subsidies.

MR. MUGICA: I think you could get a little higher return for utility-scale solar.

MR. MANCINI: Most bidders looking to buy someone else's project look over a two-year period. They see that equipment costs fell X% in the last two years and generating efficiency increased Y%, and they extrapolate from that to where they think the market will be in two more years when the project is likely to be built. You have to take a leap of faith to believe that scale economies will continue to be achieved at the same rate.

MR. MARTIN: Sticking with rates of return, a developer can earn about 7% to build a solar project. What is his blended cost of capital to build the project? If it is higher than 7%, isn't that the story right there? Does capital cost more than what one can earn from using the money?

MR. MANCINI: It does not make any sense currently to build new projects as far as we can see.

Business Strategies

MR. MARTIN: What types of questions will you be discussing in the next Enel strategy session?

MR. STORCH: Martin Mugica will be able to relate to this. What is happening in Europe has a huge impact, and it is hard for a European company not to have its conduct be governed to a large extent by the current climate in Europe. Europeans are experiencing things they never had to deal with before — for example, 25% or higher unemployment for people under 30 years old in places like Spain, Italy and Greece — and it creates a mindset that is not exactly / continued page 6

IN OTHER NEWS

said that was not the intention and said the language will be fixed.

The opinion letter clarifies how to determine whether there has been a change of control in situations where a project is owned through tiers of partnerships and a partner in an upper-tier partnership sells his interest. The letter says one should multiply the ownership interest that someone is acquiring by the percentage interest each partnership owns in the partnership below it down the ownership chain. Thus, for example, if D acquires a 10% interest in a partnership that owns 50% of another partnership that owns the solar project, then D acquired 10% x 50% = 5% of the partnership that owns the project. If D did not already own a large enough interest that, when combined with the additional 5% would increase its interest to more than 50%, then there is no change in control.

The board plans to use the same approach to determine whether there has been an indirect change in control of a corporation.

The board's guidance is not binding on local assessors who administer the property tax. The board is taking comments on the latest draft until September 25.

In a separate development, some California cities and counties are trying to collect real estate transfer taxes when a single-member limited liability company that owns real estate is transferred.

The tax at the county level is 55¢ per every $500 in value, and cities within counties may impose an additional tax at half the county rate.

The tax is triggered by recording an instrument transferring ownership of real estate. When an LLC is sold, nothing is recorded.

San Francisco amended its transfer tax ordinance in 2008 to require taxes to be paid after a sale of more than a 50% ownership interest in a single-member LLC that owns real estate despite the fact that no transfer instrument is recorded. (The sale will also trigger a reassessment for annual property tax purposes.) Los Angeles County has not / continued page 7

Survival Strategies

continued from page 5

geared toward entrepreneurial thinking. You have to get past that first. Then the next issue is where in the world are there opportunities for growth. There is a lot of focus on the next countries that make sense. Our parent company has operations in about 40 countries. Enel Green Power is active in 22. We try to add about two countries a year to our activities. There is a lot of focus on where we think we can capitalize on relationships, our expertise or particular opportunities that may be a little ahead of the market.

MR. MARTIN: Your own focus, though, is all of North America or just the United States?

MR. STORCH: Just the US and Canada.

Some manufacturers are offering wind turbines at less than $1 million per installed megawatt in an effort to move product.

MR. MARTIN: So what does the US team discuss when it gets together every two weeks to discuss strategy?

MR. STORCH: We recently had a team building event. It has absolutely nothing to do with your question. (Laughter.) Last Friday, I joined a group of 17 of my peers and walked barefoot over hot coals.

MR. MARTIN: This is to replicate conditions in the US market? (Laughter.)

MR. STORCH: Like the rest of the team, I survived. We believe that North America remains an area with real opportunities. Really large projects get done here. You have so many potential offtakers for electricity among the investor-owned utilities, municipal utilities, electric cooperatives and federal marketing entities.

I spend a lot of time explaining to Europeans that the United States is one country, but it is as fragmented as Europe as far as electricity markets are concerned. There are a dozen transmission regions, and you have to look at each in a very different way. What is the average price of electricity in the United States? Most people in this room would say the question is pretty silly. Too many people in Europe do not understand why.

MR. MARTIN: A former CEO of your company once told me that the United States is too chaotic, which was an interesting comment from the CEO of a company based in Italy, but he is right. It is 51 different regulatory regimes if you count the states and District of Columbia, with federal rules superimposed on top.

MR. STORCH: People generally like to keep things simple, but when you start talking about the United States and what it takes to do a project, even the simplest project is incredibly complicated. When we explain our projects to people in Europe, we start with the most predictable part: there are contracted revenues. It is hard to compare this approach to the simpler feed-in tariffs in Europe, but it has become clear lately that the tariffs carry political risk as governments across Europe scale them back. A little complexity is now tolerable for opportunity.

MR. STORCH: Paul Gaynor, when you strategize, is it as simple as asking in which states with high RPS targets you can secure a power contract? Is that all it comes down to?

MR. GAYNOR: Pretty much. Our business is to track where the RFPs are being issued. In the next nine months or so, utilities with obligations under renewable portfolio standards in the parts of the United States where we are most active will probably issue 10 RFPs. So the business model is actually quite simple. We don't have to walk on any hot coals, other than at our board meetings.

MR. STORCH: I highly recommend it. (Laughter.)

MR. GAYNOR: The other place where we are focused is on acquisitions outside our existing markets for projects that are trying to do things that are complicated and hard and where there is potential upside.

MR. MARTIN: Martin Mugica, what is on Iberdrola's strategic plan?

MR. MUGICA: There are three items. One is to improve operations, so we are working hard to increase production, reduce expenses and try to figure out ways to generate more revenue from our existing assets. That is our primary focus because we do not have big investment plans in the near future.

Next, we are trying to optimize our portfolio. We are looking at the geographic distribution of our assets and asking whether we might do better by redeploying assets, to the extent one can, in areas where markets are more likely to grow.

Finally, we are trying to reduce our merchant exposure by signing more long-term power contracts.

MR. MARTIN: Paul Gaynor, wind turbine suppliers are suffering from too much manufacturing capacity in relation to demand for new turbines. Are you being offered good deals by turbine suppliers?

MR. GAYNOR: Absolutely. Six months ago, we asked one manufacturer whether it would give us discounted pricing on turbines because of the risk that Congress will fail to extend production tax credits for wind farms and the answer was, yes, as long as we would pay full price if the PTC is extended. We said we are not sure that makes sense since we are taking the risk, we are building the project, and you will be able to keep your factories going.

Today, the tone of the conversation is very different. Now turbine manufacturers are talking about numbers that are staggering, less than $1,000 per installed kilowatt, regardless of whether there is a PTC. In our markets, pricing like that could make sense, so we are absolutely trying to take advantage of it.

Raising Capital

MR. MARTIN: Let's talk about the difficulty of raising capital. Martin Mugica, you are backed by a Spanish parent. We read about the economic troubles in Spain. Mike Storch, you are backed by an Italian parent. We watch as the Italian government tries to stabilize the economy in the face of demands by the European Union for more austerity. Paul Gaynor, your company has had to rely on expensive private equity and your wits. Bob Mancini, your company is using Goldman Sachs money. How easy is it for any of you in this market to raise risk capital?

MR. GAYNOR: It is hard. We have raised more than $6 billion in the last five or six years, so we are good at it, but we don't have a parent company on whom we can rely, so it all has to come from within and on the backs of our projects.

We have had two recent notable successes. We did a high-yield bond offering last year, the first / *continued page 8*

IN OTHER NEWS

amended its ordinance, but the county recorder interprets the existing ordinance to require a transfer tax to be paid when a controlling interest is transferred in a legal entity that owns real estate. The recorder says state law gives the county the right to collect taxes in such cases.

A TAX EQUITY TRANSACTION with aggressive features was struck down by a US appeals court in August.

The decision calls into question whether a "fixed-flip partnership" structure that has been used to finance some wind and solar projects works, at least in its earliest form.

The decision may also require rethinking of some "pay-go" structures where tax equity investors pay for tax credits as the credits are received.

The case is called *Historic Boardwalk Hall LLC v. Commissioner.*

The New Jersey Sports and Exposition Authority, or NJSEA, took on renovation of a sports arena and hall called East Hall in Atlantic City that was originally built in the late 1920's and was the site of the Miss America pageant starting in 1933. The renovation work began in 1998. The state issued $49.5 million in bonds and used another $22 million from the New Jersey Casino Reinvestment Development Authority to fund the work.

Since East Hall is listed as a national historic landmark by the US government, the work qualified potentially for tax credits for 20% of the cost. The tax credits are claimed in the year the renovation work is completed. The state was not in a position to use the tax credits, so it essentially bartered them for capital to help fund the project in a tax equity transaction.

The transaction was complicated. NJSEA first leased East Hall from the Atlantic County Improvement Authority for 87 years at $1 a year. NJSEA then subleased East Hall to a partnership in which NJSEA retained a 0.1% interest. The partnership allocated 99.9% of depreciation and tax credits to Pitney Bowes. Pitney Bowes was also entitled to annual / *continued page 9*

Survival Strategies

continued from page 7

one in the renewable energy business. The bonds were issued at 10.25% interest. We are using the money raised as equity in our 2011 and 2012 projects. Raising 10% equity is pretty good.

Then we closed on a joint venture transaction with Emera, a utility holding company based in Nova Scotia, where we essentially sold 49% of our operating assets in the northeast. They come to about 400 megawatts. Emera has an ongoing obligation to provide 49% of the equity at financial closing on our new 1,200 megawatts in the northeast at a pre-determined cost of capital, which is at a competitive rate.

These two transactions have put us in a good position in the northeast. Companies like ours have to fight and claw to create some liquidity and build value.

MR. MARTIN: Bob Mancini, you are pivoting from solar into natural gas-fired power plants. Goldman Sachs is willing to keep investing freely in that sector?

MR. MANCINI: Even though we are owned by Goldman Sachs, it is probably the hardest place to tap for capital.

MR. MARTIN: Equity is always the most expensive capital no matter who is supplying it.

MR. MANCINI: Our equity funding is largely coming from Goldman Sach's balance sheet, but our projects have to be structured to use as much project financing as each project can support from external sources. Therefore, it is imperative for us to have a long-term power contract for each project from a utility with a good credit rating. Projects with credit-worthy PPA are no trouble to finance.

MR. MARTIN: Are you finding the utilities more receptive to buying power long term from gas-fired plants than they are from wind or solar projects?

MR. MANCINI: It depends on the part of the country. California is a good place to be. However, there has been a general shortening of PPA terms. Long term is no longer 20 years. Long term now is 10 years.

Sage Advice

MR. MARTIN: We have just a few minutes remaining. Let's try to sum up. This is a challenging time. It is a transition year for wind, but perhaps less of one for solar. What would you tell a CEO in this sector is the right survival strategy?

MR. STORCH: With adversity comes opportunity. Right now I believe the opportunity is extraordinary. For example, let me put in a plug in for something called "net zero", which is very important for the renewable energy business. Net zero is a way to piggyback on a peaker, where two projects, a peaking power plant and a renewable energy facility, use the same interconnection rights and share them in a way where their combined output at any point in time never exceeds the inter-connection capacity, but the combined installed nameplate capacity greatly exceeds what the interconnection allows for. An example would be a 400-megawatt interconnection with 600 megawatts of generation. It might be a peaker and a wind farm. The opportunity is for overbuilding renewables against a smaller interconnection site or for combining renewables. It is something that all of us should be pushing the Federal Energy Regulatory Commission and regional transmission organiza-tions to allow.

MR. MANCINI: Diversification is key because, as one market ebbs, the other flows, and that is what we have been trying to take advantage of in our own portfolio. I agree with Mike Storch that there is enormous opportunity over the next five to 10 years. Reserve margins will shrink with economic growth, and there will be a need for additional capacity. We will need a lot of peakers to fill in the gaps in electricity supply in markets where wind and solar supply a large share of total electricity.

MR. MARTIN: Renewable energy developers have done very well in a market with low load growth. Think of how well they could do if there was actually growing demand for the product. Paul Gaynor?

MR. GAYNOR: Fasten your seat belts, get your costs down, and try to become self funding. We have finally crossed the Rubicon and no longer have to go outside to find money to fund development. It is a great place to be. On the capital rais-ing side, I would go down every path you possibly can — any kind of crazy idea that bankers or lawyers bring you — pursue it because it might just work out for you.

MR. MUGICA: I think it depends on what type of company you are. If you are a small developer, it is all about survival. Believe me, you have to survive because there will opportuni-ties in the future, but it will be really hard to survive in this environment if things do not change. If you are a big company, then you have to manage your portfolio. You have to start trying to get good assets, dispose of other assets, look for synergies and improve your position in the right markets. Try to extract the maximum value for your existing assets by better integrating your facilities with the grid, creating value-added products for your customers and optimizing your capital structure. ◎

Treasury Cash Grant Update

by Keith Martin, in Washington

Developer fees are receiving more scrutiny from the Treasury in applications for section 1603 payments for renewable energy projects.

The term "developer fee" is often misused. The classic developer fee is a success fee that a project company pays a separate development company as a reward for pushing the project across the finish line. The Treasury is generally limiting such fees paid to affiliated development companies to 3% to 5% of the project cost. Exceptions are where a development services agreement was in place before 2009 or development took an unusually long time and the developer had a lot of capital at risk.

People frequently misuse "developer fee" to refer also to a gain on sale of a project after construction. For example, a developer who sells and leases back his project may have a gain on sale. The Treasury is generally limiting the mark up it will allow in cases where a project is sold to a third party, including in a tax equity transaction, to 10% to 20% above cost.

The term "developer fee" is sometimes also used to refer to a cash distribution by a project company to its owner. Most project companies are limited liability companies. They are usually treated as partnerships if they have at least two owners or are ignored — "disregarded" — if there is a single owner. A cash distribution by a project company treated as a partnership to a partner does not usually add to basis. A cash distribution by a disregarded project company to its sole owner does not add to basis either.

September 30 Deadline

All remaining cash grant applications must be filed with the Treasury by September 30, 2012. Congress wanted Treasury to have a sense by September 30 for how many remaining claims there may be on the program.

In cases where a project is not yet in service, a preliminary application must be filed demonstrating that the project was under construction by December 2011, and then a final application must be filed within 90 days after the project is put in service. The only projects that still qualify for section 1603 payments, or cash grants, are projects / continued page 10

IN OTHER NEWS

preferred cash distributions of 3% of the capital it contributed for an interest in the partnership. NJSEA had a call option to repurchase the Pitney Bowes interest after five years for the market value of the interest, but not less than any part of the 3% preferred cash return that Pitney Bowes had failed to receive. Pitney Bowes had a "put" to force NJSEA to buy the interest after seven years at the same price that NJSEA would have had to pay under the call option. (The options were never exercised.)

Pitney Bowes made capital contributions for its interest in the partnership. The first capital contribution, shortly before renovation was completed, was just $650,000. It contributed roughly another $19 million in three installments later as tax credits were received.

The partnership guaranteed Pitney Bowes that it would receive the expected tax benefits.

NJSEA guaranteed Pitney Bowes that it would cover any cost overruns or operating cost deficits on the project.

NJSEA described the transaction as a "sale of historic tax credits" in the offering materials and other documents while marketing the transaction.

The court said Pitney Bowes was not a real partner and was just attempting to buy tax benefits.

A partnership requires an intention to join together for the purpose of sharing in the profits and losses of a genuine business. Pitney Bowes was not exposed to operating losses because of the NJSEA guarantees. The court said it had no meaningful downside risk: it was not required to make its capital contributions, after the first $650,000, until after it had verified the amount of tax credits it was being allocated for each period. It was assured of receiving the tax benefits because of the tax indemnity. The tax benefits were not even at risk from the possibility the project might not be completed because the project was essentially fully funded by NJSEA before Pitney Bowes invested. Its capital contribution went to pay a developer fee to NJSEA and buy a guaranteed / continued page 11

Treasury Cash Grants

continued from page 9

that were under construction by the end of last year.

The Treasury has been responding by email to preliminary grant applications acknowledging that the requirement to file has been met, but reserving the right to question later whether construction started in time.

Many solar rooftop companies took delivery of panels or inverters late last year and will be considered to have started construction of future rooftop installations that use this equipment, provided the stockpiled equipment used amounts to more than 5% of the basis ultimately used to calculate the cash grant on the installation.

The Treasury is taking the position that a separate application must be submitted for each future project or rooftop system. The Treasury does not need to know by September 30 the customer name or location of each project. However, it does need to know the particular equipment that will be dedicated to each project.

Suppose a company stockpiled 100X of solar panels in 2011. It can divide up the panels for use in separate projects however it wishes. It would then submit a separate application for each batch of equipment. The Treasury will assign a separate TAN or tracking number to each equipment batch. It will then want to match that number to the eventual project built.

The company cannot later combine equipment to reach the 5% threshold for a single project. For example, suppose it submits 20 separate grant applications for batches of 5X panels each and the 5X panels cost $10,000. It will only be able to claim cash grants on projects using these panels that have a basis for grant purposes of less than $200,000 ($10,000 ÷ 0.05).

It does not need to identify the serial numbers of the particular equipment assigned to each preliminary grant application. It is enough to say project 1 will use 5X of the stockpiled panels without identifying the location of the project or customer or the specific panels by serial number.

There is a risk, if a company installs a rooftop system using two batches of stockpiled equipment, that the Treasury will say the installation is a single project and does not qualify for a grant. Suppose each grant application submitted covers two panels and one inverter. The company installs a system using four panels and two inverters and reports it as two separate systems. There is a risk that the Treasury will say the installation is a single project.

The Treasury has been taking a harder look at developer fees in cash grant applications.

Lawsuits

Three suits against the Treasury cash grant program are pending in the US Court of Federal Claims.

The government's frustration against a solar company that filed one of the suits has now led to charges that the solar company tried to defraud the government.

Pure Power Development filed suit in February 2010 seeking $2.33 million in grants that it says it was denied on 25 mobile solar systems that were mounted on the backs of flatbed trucks. According to documents filed in the case, the company bought the systems from the manufacturer for $4.30 to $5.80 a watt for regular systems and for as much as $6.80 a watt for "super" systems, resold them to affiliated companies for $19.45 to $26.24 a watt for regular systems and as much as $45.50 a watt for super systems and claimed cash grants on the resale price. The company produced an appraisal suggesting the high resale price was the market value. The price was not actually paid: Pure Power Development took back notes from the buyers for the price. The National Renewable Energy Laboratory staff who reviewed the grant applications did not believe the systems were ever put into service. The government says the company made direct cash sales to third parties at lower prices during the same period.

NREL recommended to Treasury officials in Washington that the government pay much lower grants or no grants at all. Its report said, "the Treasury 1603 Review Team has pointedly asked [the applicant] to provide a rational cost basis for their property and has suggested the cost basis should be less than $50,000. Despite this, [the applicant] has worked even harder to justify the cost basis to Treasury."

The government asked the court last year for a "summary judgment" in its favor on grounds that the government has discretion whether to pay grants. The court declined. It said the Treasury is required to pay a grant to anyone who satisfies the eligibility requirements in the statute.

The government amended its response in the case in July to accuse the solar company of trying to defraud the government. It says the company should forfeit any right the company has to grants on the systems and pay damages.

Two other suits have been filed against Treasury this year. Clean Fuel, LLC filed suit in February 2012 after being denied grants on Cummins generators that it added at two existing biodiesel plants in Florida. The plants make biodiesel from waste soy, palm nuts and some waste animal fats. Clean Fuel bought them in early 2009 from the original owner and added the generators a year later to make electricity for use in the plants. Treasury appears to have denied grants on grounds that the company was asking for grants on used property. The company would not have qualified for production tax credits on the electricity because there is no sale of the electricity to third parties. However, the Treasury does not appear to have raised this as a bar to a grant.

The third suit was filed in May by a small electrical contractor, RCIAC, in Dallas that installs solar rooftop systems on homes and businesses. The contractor feels it was shortchanged on the grants it was paid on 18 systems. Each grant was roughly 85% of the amount claimed. (One grant was 77%). The contractor set up a separate partnership called LCM Energy Solutions of which the company sales head was listed as CEO that bought the systems, after installation from RCIAC, and then leased them to customers.

Bankruptcy

The Treasury plans to try to get back all or part of a $6.5 million cash grant that it paid the Thompson River project in Montana. The project is a coal-fired power plant that the owners converted to run on wood. However, it is not clear whether the plant ever operated after the conversion, according to published reports. The owner is now in a chapter 7 bankruptcy proceeding in which the business will be liquidated. A bankruptcy filing alone does not lead to recapture / continued page 12

investment contract from an insurance company to ensure money would be available to buy out Pitney Bowes after the tax credit recapture period.

The court said that any upside potential for Pitney Bowes was illusory. In theory, the company could continue to share in cash, but in practice, the court said, the partnership was expected to lose money and avoided a write down of its assets only after persuading its accountants that the state would make good on the losses.

> *This is the second tax equity transaction involving tax credits for historic renovations with which the courts have found fault in a little over a year. A different US appeals court rejected a transaction in a case called* Virginia Historic Tax Credit Fund 2001 LP et al v. Commissioner *in 2011. (For earlier coverage, see the June 2011* NewsWire *starting at page 29.)*

GILLETTE opened the door to possible refund claims for companies operating in multiple US states.

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, its changed its law to require double weighting be given to the sales factor.

Gillette and five other companies sued the state for $34 million / continued page 13

Treasury Cash Grants

continued from page 11

of a grant. However, recapture would be required if the plant never operated or is permanently removed from service as a wood-fired power plant. Any claim by the government would be as an unsecured creditor.

At least two other prominent grant recipients have also filed for bankruptcy: Raser Technologies, a geothermal developer, and Sterling Energy Systems, Inc., a solar developer. ◎

New Trend: Combining Gas with Wind and Solar Projects

by Paul Kaufman, in Los Angeles

First Wind proposed a change in August to the 500-megawatt Baseline wind farm that it is developing in Oregon. The company proposes to add up to 200 megawatts of natural gas generating capacity. The combined wind and gas capacity will remain at 500 megawatts. The company gave notice in a public document posted to the Oregon Energy Facility Siting Council website.

Is this a new trend or are such projects likely to remain rare?

Compelling Economics

Four factors could make such combinations a trend.

The first such factor is the decreasing price that offtakers are willing to pay for as-available energy, a result of lackluster electricity demand and low natural gas prices. A short-term forecast produced by the US Energy Information Administration shows natural gas spot prices at the Henry hub are expected to increase by only $0.39 per mmBtu in 2013 over 2012 prices that averaged $2.95 per mmBtu. EIA has forecast a similarly weak increase in retail electricity prices of 0.9% from 2012 to 2013. In its "2011 Wind Technologies Market Report," the Lawrence Berkley National Laboratory shows substantial decreases in power purchase agreement prices for wind in power purchase agreements executed in 2011 (when compared to those executed in 2010). LBL prepared this report for the US Department of Energy.

While many factors have led to this decrease in prices, the effect is that wind-generated energy has become a commodity in the marketplace. While utility purchasers are requiring a greater level of proof and security that developers can deliver on their obligations under a power purchase agreement, utilities are nonetheless looking solely to price as a way of distinguishing one wind project from another. The characteristics, experience and qualities of the developer are secondary.

Wind-generated energy is intermittent. By firming wind energy (through the addition of a thermal resource), a developer can distinguish the product sold from that wind project from the intermittent product produced by other wind projects that have not added thermal generation. The "firmed" wind-produced energy can thus be distinguished from the commodity of intermittent wind-produced energy. The specialized, "firmed" product should fetch more in the marketplace than the intermittent wind-energy commodity.

The second factor is market size. In the "2011 Wind Technologies Market Report," LBL presents forecasts from a number of different sources that collectively indicate that wind capacity additions in 2012 will be between 7,280 megawatts to 12,000 megawatts. The same report shows forecasted capacity additions for 2013 in the range of 1,000 megawatts to 2,400 megawatts and 600 megawatts to 3,000 megawatts in 2014 (if one assumes that Congress fails to extend the production tax credit or investment tax credit for wind past its current expiration date of December 31, 2012). In addition to the possible expiration of tax credits, LBL identifies a number of other limitations on the size of the market, including low natural gas prices, low wholesale electricity prices, inadequate transmission and modest electricity demand. Assuming these predictions are realized, the obvious conclusion is that renewable markets will shrink. In a shrinking market, differentiating what you have to sell is a good thing.

The third factor is cost. Wind projects sell their electricity solely for energy payments that are a function of the output. They do not also receive capacity payments. Thus, wind developers generally want more electricity over which to allocate the fixed costs of their projects. The more megawatt hours produced by a project, the lower price per megawatt hour the developer has to recover from the utility purchaser and the higher the likelihood that the developer will meet (or beat) its financial targets. By adding a thermal resource to a wind project, the developer can produce more energy over a given amount of capacity and time.

The fourth factor is the ratio of revenue to the fixed costs of a project. Adding thermal generation to an existing wind project, or, in the reverse, adding wind generation to an existing thermal generating plant that is operated as a peaker, will increase the ratio of revenue over the fixed costs associated with facilities that can be shared, such as an O&M building and interconnection facilities. By combining a wind resource and thermal resource, the developer can generate energy with one resource while the other resource is not operating.

Interconnection costs can be a major hurdle to jump in meeting financial return expectations. Interconnection facilities tend to be "lumpy" as their capacity to transmit energy is generally greater than the electricity produced by the associated generating plant. Even with a robust wind source, wind projects will not use all of the takeaway capacity provided by the interconnection facilities generally required by the utility. In the same way, a thermal peaking plant will generally not use all of the takeaway capacity provided by its interconnection facilities.

Challenges

All of these considerations lead to the conclusion that the combination of resources is a positive development as it may improve profitability, differentiate wind projects and the energy produced by them, and improve the efficiency of the capital deployed by a developer. However, there are other factors to consider when considering whether the combination of a thermal resource and a wind resource makes sense.

First, adding a turbine or reciprocating engine to a wind project means that you will have to address the myriad of issues involved in developing and permitting a thermal resource. The developer's wind project may have a superior wind resource, but may be located far from the gas pipelines necessary to supply fuel to the thermal portion of the project. Building a long lateral pipeline to interconnect the project to the interstate pipeline system creates yet another fixed cost to allocate.

The security and nature of the fuel supply are also issues. Developers know well the increasing scrutiny applied to wind resource studies and the deductions to net capacity factor that have been imposed by third-party consultants in recent years. What requirements for security of the project's fuel supply will lending institutions impose on the thermal portion of the project? Will lenders return to the requirement of prior years where a firm fuel supply and transportation / continued page 14

IN OTHER NEWS

in refunds in 2010 arguing that they are entitled by law to use the formula in the multistate tax compact. A California appeals court agreed in a decision on July 24.

The court announced on August 9 that it would reconsider the decision. Estimates of the potential cost of the decision to California vary, but start at $100 million a year. The decision is expected to be appealed to the California Supreme Court and possibly ultimately to the US Supreme Court.

The state enacted a bill in July, shortly before the appeals court released its decision, 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.

Refund claims are now expected in other states.

Fourteen of 20 states that belong to the multistate compact have moved away from the three-factor formula.

A majority of state tax advisers listening to a recent webinar on the subject said they are likely to advise their companies to pursue refund claims; 87% of participants said they would advise pursuing such claims in California and 78% said they would advise making claims in other states.

A LARGE SALES TAX ended up having to be paid on construction of an ethanol plant in Nebraska, but it could have been avoided if the construction contract had been drafted differently.

Bridgeport Ethanol paid a contractor $67 million to build an ethanol plant. Nebraska, like many states, exempts equipment purchased by a manufacturer for use in manufacturing from sales and use taxes. Unfortunately, the contractor in this case bought the building materials and then conveyed the completed plant to Bridgeport. The contractor is not the manufacturer. The contractor elected to be taxed as the consumer of the building materials, triggering a tax at the contractor level rather than on the higher price / continued page 15

Net Zero

continued from page 13

were required for the full term of a power purchase agreement? Or will they recognize the different operating characteristics expected of a thermal resource that may be used only to firm wind generation?

A developer acquires site control for a thermal project in a different manner than site control is acquired for a wind project. These differences are driven by a number of factors. For example, while wind projects require, in total, more land to accommodate setbacks and other land use restrictions per megawatt of installed capacity, land leased for a wind project is available to the lessor for other uses such as farming or grazing. The American Wind Energy Association reports that wind projects require the exclusive use of only 5% or less of the land leased for a wind project. While the total acreage used for thermal project development is less, the thermal project will require exclusive use of that land. In turn, this implicitly leads the developer to purchase the land as the prior owner will no longer be able to use or have access to the property.

Second, even in states that have adopted "one-stop shopping" for permitting new power plants, a developer of a combined wind and thermal power plant will be working with two entirely different permitting regimes. Thermal generating plants have to meet air permitting requirements, get approval to use water if the thermal resource is water cooled, and potentially address issues regarding cooling water disposal. While the complexity of permitting a thermal power plant varies depending on the specific type of generation deployed, its water requirements and its emission control technology, the fact remains that thermal generation has a different permitting regime than wind.

Even where a particular characteristic of power generation, for example, noise, is present in both wind and thermal generation, the noise characteristics and, thus, permitting parameters, of a thermal plant will be different than those of a wind facility.

Third, the addition of a thermal resource to a wind project may trigger new permitting requirements if the addition of the resource pushes the project over a permitting threshold. Thresholds are established in a number of different ways under state and local law.

In some states, permitting of wind projects is within the jurisdiction of county or city land use agencies, while permitting a thermal resource is not. For example, the Washington Energy Facility Sitting Council has jurisdiction over any stationary thermal generating facility with electrical generating capacity of 350 megawatts or more, including associated facilities. Yet, Washington EFSC review of wind projects is discretionary with the developer. Will states that have similar state-wide regimes as Washington look at the wind project as an "associated" facility when determining the size of the thermal generating plant? Or will the addition of a thermal generating plant result in mandatory, rather than discretionary, state-level review of a wind project?

Expect to see more gas peakers added to renewable energy projects, and vice versa. There are several potential benefits.

Even in situations where primary jurisdiction for permitting is with a county or city land-use agency, the addition of a thermal resource can trigger additional review and resulting delay. A number of jurisdictions have adopted wind resource areas in which wind is an approved use of the land subject only to either a conditional use permit or, as in Riverside County, California, a commercial "wind energy conversion" systems permit. The benefit of these wind resource areas is that the process for reviewing wind projects is clearly spelled out and most of the conditions for wind projects are also found in the agency's rules or ordinances. The question is whether the addition of a thermal generating facility will exclude the entire project from the processes and benefits intended by creation of these zones or whether two separate processes will be required for review and permitting of the project.

Fourth, the addition of thermal generation may trigger additional interconnections studies and require an additional interconnection application. There are a number of iterations related to interconnection that should be considered.

As a general matter, if you are adding thermal generation to a wind project, or wind generation to a thermal project, and the total capacity of the two resources is within the capacity reserved in the original project's interconnection agreement, then you will still be subject to additional studies and may also be subject to additional interconnection and upgrade costs as well as restrictions on the operation of the two facilities. The mechanics of how this will be determined vary among transmission providers and independent system operators (ISOs).

Net Zero Interconnection

The mechanics of adding more capacity adjacent an operating power plant are expressly addressed in attachment X to the Midwest Independent System Operator's tariffs, which provides "net zero interconnection service." This form of interconnection service allows a new power plant to use the existing interconnection capacity reserved for a power plant that is already operating, so long as the total interconnection capacity used by the two power plants does not exceed the amount of capacity reserved for the power plant that is already operating. The tariff provisions apply equally to wind generation that is being added to operating thermal generation and thermal generation that is being added to operating wind generation.

Before providing net zero interconnection service, meaning allowing a new power plant to use part of the interconnection capacity dedicated to a power plant that is already operating, MISO will conduct a number of studies, including reactive power, short circuit and fault duty, and stability analyses. The tariff says that steady-state (thermal and voltage) analyses may also be performed as necessary to ensure that all required reliability conditions are studied. The tariff clearly contemplates the potential imposition of additional interconnection and transmission upgrade requirements.

To qualify for net zero interconnection service, the generator must submit an application for service and include in that application a memorandum of understanding that shows the applicant intends to enter into a "transmission utility monitoring and consent agreement" upon execution of an interconnection agreement. In addition, the applicant must include an executed copy of an "energy displacement agreement" with the owner of the operating project that must specify the term of operation for the operating and new / continued page 16

IN OTHER NEWS

for the completed plant.

The Nebraska Supreme Court said in August that the ethanol company was out of luck. It rejected the company's claim that the contactor was merely its purchasing agent. The statutory authorization for appointment of a purchasing agent is only available to non-profit organizations and schools. It did not matter, the court said, that Bridgeport had a duty to reimburse the contractor for the taxes the contractor paid.

The case is Bridgeport Ethanol LLC v. Nebraska Department of Revenue. *The court released its decision on August 10.*

AN INTERESTING INBOUND INVESTMENT STRUCTURE into the US was upheld by the US Tax Court.

The structure let Scottish Power "strip" earnings from its US subsidiary, PacifiCorp, during the period 2000 through 2002 by pulling the earnings out of the United States as interest on shareholder capital put in as debt and deduct the interest on the debt in both the United States and the United Kingdom. The company unwound the structure in late 2002 partly in response to a change in US tax regulations that would have caused the interest to be treated as dividends.

Scottish Power acquired PacifiCorp, a US utility, by setting up a chain of three entities and merging the bottom-tier entity into PacifiCorp with PacifiCorp as the surviving company. The PacifiCorp shareholders received $6.9 billion in Scottish Power stock and ADRs traded on the New York Stock Exchange.

The chain of three entities had at the top two wholly-owned UK subsidiaries, NA1 and NA2. Next down the chain was a Nevada general partnership called NAGP that Scottish Power elected to treat as a corporation for US tax purposes but that was viewed as a pass-through entity for tax purposes in the UK.

Immediately below NAGP was a US acquisition company that merged into PacifiCorp.

Scottish Power capitalized NAGP largely with debt. It made two / continued page 17

Net Zero

continued from page 15

projects, the total generating capacity of the two projects and the mode of operation for energy production for both projects. The energy displacement agreement is subject to negotiation with the operating project and is not required if the applicant is the owner, or an affiliate, of the operating project.

Behind the Meter

In its "behind-the-meter" rules, the California Independent System Operator allows operating wind and solar generators to add capacity under their existing interconnection agreements and avoid much of the interconnection process. However, this can be done only in limited circumstances. A key limitation is that the incremental generation, when added to the operating capacity, cannot create additional deliverability over that studied by CAISO for the operating capacity. Further, the sum of the total nameplate capacity of the existing facility plus the increase in capacity cannot exceed in 125% of the previously-studied capacity, and the incremental capacity cannot exceed 100 megawatts.

In circumstances where the actual nameplate of the original facility is at or near the nameplate capacity studied by CAISO, these limitations will severely restrict the amount of incremental capacity that can be added. There may be greater flexibility to use the behind-the-meter rules in cases where the nameplate capacity studied is greater than the nameplate actually built. CAISO has other rules regarding partial completion of generating plants.

The behind-the-meter rules also require that the incremental capacity be placed in service under a separate breaker so that it can be metered separately at all times. The tariff gives CAISO the authority to open the expansion breaker if the total output of the combined generation exceeds the originally-studied capacity. The limitations on deliverability of the combined resource, when combined with the risk that CAISO will open the breaker on the project, will create problems if the duration of the disconnection is long and the notice for disconnection is short.

Of course, the generator always has the ability to file a separate interconnection application for the incremental capacity. This outcome may promote greenfield development of combined resources over the addition of incremental capacity to an existing facility. In both cases, the interconnection applications will be considered in the study process.

Such combinations would let wind farms offer "firm" electricity potentially at higher prices.

The MISO and CAISO tariffs are less than clear about what happens to greenfield combined resources. The MISO and CAISO are not alone. The transmission tariffs of other ISOs and transmission providers also lack a clear statement of how combined resources will be studied and authorized for interconnection. Differing ownership of the resources that may be combined adds ambiguity to this topic. Whether this is an issue will depend on the express language of the tariff and the interpretation of those tariffs by the relevant ISO staff.

Fifth, there is an open question whether the combined project will continue to be considered wholly or partly an intermittent resource. As a result, there is an open question whether a combined project will continue to qualify for programs that offer some protection against imbalance charges provided to intermittent resources. The "participating intermittent resource program" provided by the CAISO is one such program.

Under the California program, qualifying intermittent resources are allowed to net their imbalances on a monthly basis, and the intermittent resource owner is charged for net negative imbalances by taking the net amount of the imbalance and multiplying it by the average locational marginal price for the node at which the resource is interconnected. This substantially reduces the imbalance charges for intermittent resources when compared to the rules for other resources, which are charged against real-time LMP prices and not allowed to net over a month. While the overall effect of combining a wind and thermal project should reduce imbalances, will the California ISO allow a developer to remain certified as an intermittent generator if the wind project is now a wind-thermal project? If it does not, then how will it allocate the scheduling penalties that are assessed against non-intermittent facilities if schedules do not match actual deliveries?

Finally, will the addition of a thermal resource allow the developer to increase the price of its differentiated product above that of as-available wind energy? Utility offtakers may welcome a more predictable source of electricity, but will they price the electricity produced by the thermal resource as if it was purchased on the spot market or recognize the capacity value of the combined resource? The market for a combined wind and thermal power plant will have to be tested before anyone can answer this question.

Other Issues

Developers of combined projects will also face construction and engineering challenges if they choose to use a contractual vehicle other than a full engineering, construction and procurement contract for construction of the combined plant. While a disaggregated engineering, procurement and construction model is currently market for wind farm construction, will the same be true if a thermal resource is added to the project? One can expect that the number and type of indemnities required of a contractor and, perhaps, the developer will increase if a developer adds a thermal resource to an operating wind farm or vice versa. While phasing wind projects is common, the combination of the two resource types adds some complexity to what has become commonplace.

Whether or not combining resources becomes a trend, one hopes that the issues identified in this article can be resolved in a manner that makes such combinations easier. While this article has focused on the combination of wind and thermal generating resources, developers are also moving ahead with combined wind and solar projects and combined geothermal and solar projects. Such combinations avoid the concern that combining wind with thermal turns what is otherwise a green resource into partly a brown resource. ◎

IN OTHER NEWS

loans for $4.9 billion to NAGP that NAGP used to acquire 75% of the Scottish Power shares used in the merger. The remaining 25% of the shares essentially came down the ownership chain as capital contributions (equity).

The debt was a $4 billion fixed-rate loan at 7.3% interest for a term of 12 years, and a floating-rate loan of $892 million at LIBOR plus 55 basis points for a term of 15 years. Both loans required quarterly payments of interest.

NAGP fell behind immediately and struggled to make interest payments because dividends from PacifiCorp to NAGP fell short of what was needed. Scottish Power converted the floating-rate debt into equity in NAGP in early 2002 after being advised by PricewaterhouseCoopers that it would be hard to support characterization of more than the $4 billion in fixed-rate notes as debt. It converted the fixed-rate debt into equity at the end of 2002.

In 2006, the IRS instructed its agents to challenge use of cross-border hybrid arrangements as a tier I enforcement issue. The IRS challenged $932 million in interest deductions claimed by the consolidated group of NAGP and PacifiCorp in the United States on grounds that the "debt" was in reality equity from the start.

The US Tax Court said in June that the loans in this case were real debt. The companies treated them as such for purposes of securities and other filings. The court reviewed a list of 11 factors that the US appeals court for the 9th circuit — which is where the case will be heard if it is appealed — uses to distinguish debt from equity. It said only one of the factors pointed to equity in the case of the fixed-rate debt and two for the floating-rate debt.

The case is NA General Partnership v. Commissioner. *It is the first of a series of cases waiting for court dates involving billions of dollars in interest deductions. The US government has until at least mid-September to appeal.* */ continued page 19*

The Search for Lowest Cost Capital

Financings in the US relied heavily the last three years on stimulus grants and federally-guaranteed debt. Both are disappearing. The euro is in trouble with a Greek exit from the euro zone looking increasingly likely. European banks have pulled back from the project finance market. What assumptions should developers make about the future cost of capital when bidding to supply electricity? What new strategies are likely to emerge for raising debt and equity? For example, the solar industry continues to talk about REITs and rated portfolio debt.

Four veterans in the project finance market talked about the cost of capital at the Chadbourne global energy and finance conference in June. The panelists are Thomas Emmons, managing director and head of renewable energy and infrastructure finance at Rabobank, New York Branch, Duncan Scott, managing director and global head of private placements and project bonds at SG Americas Securities, Richard Randall, managing director and head of power and project finance at RBS Global Banking, and Carl Morales, a director at Sumitomo Mitsui Banking Corporation. The moderator is Eli Katz with Chadbourne in New York.

MR. KATZ: Carl Morales, there are declining subsidies and a lot of volatility in the bank markets. How should developers be evaluating this when they think of the future cost of capital for their projects?

MR. MORALES: We are headed for a tightening of terms and maybe some higher costs. Finance is moving from the bank market to the institutional debt market as a result of the European debt crisis and Basel III. Export credit agencies are also playing a larger role.

Banks Versus Capital Markets

MR. KATZ: Tom Emmons, what is going on with the banks in terms of funding and regulatory issues that is making it more difficult to get long-term debt?

MR. EMMONS: The bank market is segmented. The segment that is under the most duress is, of course, the European banks. There are regulatory pressures: Basel III is requiring banks making project finance loans to set aside more capital. The economic crisis in Europe is eroding the capital base. There is a deleveraging of balance sheets. Basically, as a category, European banks are under a lot of pressure, so you see them shrink, if not totally withdraw, from the project finance market in the US.

The good news, if you can see any good news in it, is that some other segments of the bank market are actually filling in fairly well. I would look at margins as an indication of supply and demand. Margins and fees have not increased significantly since mid-2009. The good news is that the banking market is somewhat resilient and the other categories of banks, US, Canadian and Japanese banks, seem to be filling the void.

MR. KATZ: Most developers are looking for longer-term debt. As you think about the different banks, who is the best target for that and why?

MR. EMMONS: Banks are intermediaries. They basically take deposits and lend them out again. Insurance companies and pension funds are really investors: they have a pool of capital that they need to invest. So per textbook corporate finance, long-term debt is better matched to institutions. Banks typically would do the shorter term or the part of project finance work where construction is involved meaning that there will be more complicated draws and repayments. Institutions like to put the money out all at once. They will do construction debt and take construction risk, but the sweet spot for institutions is long-term, low-risk chunky investments. The reason why institutions were not the main lenders to the sector in the past is that European banks over the last decade considered their cost of capital lower than it really was, so they began competing with institutions and lending up 18 years and that has basically come to a halt.

MR. KATZ: Do you see that restarting anytime soon?

MR. EMMONS: There are some non-European banks still making long-term loans. But no, I do not see that coming back. I see this as a fundamental shift mostly due to regulation and higher capital costs. I think the institutions are probably competitive again, and banks are coming down significantly in maturity.

MR. KATZ: Duncan Scott and Rich Randall work more in the capital markets. Since the place to get long-term debt is now the capital markets, will you talk about what those markets look like, how many active players there are and whether they are healthy?

MR. SCOTT: Those markets are obviously huge. Over the last five to 10 years, the capital markets have been a niche part of project finance lending. Renewable energy companies are less familiar with the capital markets. The role of these markets is growing. A number of the institutional lenders participated in loan guarantee transactions last year to the renewable energy sector. This has contributed to a widening of knowledge among institutions about renewables projects.

There has always been a very active handful of life insurance companies who have understood these projects and have been active in them. Of obvious interest to this audience is how we widen institutional participation in the sector. That is the ongoing challenge, and it has accelerated in the last 12 months with the withdrawal of many long-term lending banks. Many developers have no choice but to look to institutions and to begin to adapt their requirements, their returns and their structure expectations to an audience that is similar but different.

MR. KATZ: Rich Randall, banks are notoriously inflexible. Do you have the same thing in the capital markets? Do you get more flexibility in terms of who your offtaker is? Do you get more flexibility in terms of tenor? What sorts of things do you get in the capital markets that make it a more advantageous place for developers to borrow?

MR. RANDALL: Our developer clients would probably say the capital markets are less flexible than the banks. I think the only flexibility you get is on tenor. Essentially the two markets are almost identical in structure and in creditor arrangements. There are still tranche deals. They are still very similar.

The disconnect comes as the bank markets fade and focus more on the short-term aspects of projects like getting through construction and we start to fund these projects as 25- to 30-year assets in the institutional debt market. There is a bit of a breakdown in the market right now as developers want to retain flexibility to refinance long-term debt while insurance companies and pension funds want a truly long-term instrument. We have seen a lot of flow in the last two years compared to the recent past. I would have expected to see more.

Banks tend to be gravitating to a 5- to 7-year structure. Insurance companies want 20-year debt. There is a void in the market for a 10-year type of instrument, and it will be interesting to see whether institutional money fills that gap. Pricing has crept up, and we are now looking at pricing in the institutional debt market that is more akin to bank loan-type pricing. The low rates that the European banks were offering in the last five years are starting to move upward. / continued page 20

IN OTHER NEWS

SOUTH AFRICA is expected to see a significant number of renewable energy projects under its so-called REFIT program reach financial close shortly.

The program seeks to procure 18,000 megawatts of renewable energy over the next 20 years.

The first phase of the program to procure 3,725 megawatts by 2016 launched in August 2011. There are five "bidding rounds" in the first phase staggered from November 4, 2011 to August 13, 2013.

The program has attracted keen interest from developers, investors and engineering, procurement and construction contractors from across the globe, including the US, Germany, Italy, Spain, France, China and India.

Bids for 53 projects amounting to 2,128 megawatts were received by the Department of Energy in round 1. Of these, 28 bids, representing 1,416 megawatts, were selected as preferred bidders. These are made up of 18 solar photovoltaic projects, representing 631 megawatts, two concentrated solar power projects, with a combined capacity of 150 megawatts, and eight wind farms, representing 633 megawatts.

Financial close for these projects had originally been scheduled to occur by June 19, 2012 before the Department of Energy extended the date to the end of July. This date was then postponed by the Department of Energy citing the finalization of internal and regulatory approvals by various counterparties. Subsequently, the Department of Energy indicated that it would be sending requests to bidders for an extension of the bidding period beyond the August 31, 2012 bid validation period, effectively putting the market on notice that the financial-close period could extend beyond that date. Despite these delays, it is widely expected that the process for closing the first of the round 1 projects will commence soon.

Seventy-nine bids for 3,200 megawatts of capacity were submitted for round 2. Following the round 2 evaluation, 19 additional projects representing 1,043 / continued page 21

Lowest Cost Capital

continued from page 19

There is an opening for institutional money to fill that gap.

MR. SCOTT: Renewable energy developers are looking for long-term money to match their assets and talking to both institutions and banks. The fundamental difference between the two markets is the institutional debt market is interested in lending long term at fixed rates. It is potentially a game-changing perspective for developers. The insurance companies and pension funds do not have the same long-term experience with performance of these assets that the banks have. They have not been tracking the technology changes. They end up looking through the prism of the rating agencies. The rating agencies color the views of a lot of institutions.

The rating agencies have been skeptical about wind projects and wind resources. They remember one high-profile project that they rated several years ago that did not perform as expected. They are unaware that 95% of the transactions turn out well. It is a chicken-and-egg problem to kickstart the market.

Term B Loans

MR. KATZ: Rich Randall, what is a term B loan and where does it fit in the capital structure?

MR. RANDALL: It is essentially the same as bank debt. It has a floating rate that is LIBOR based and a tenor of seven years. It can be prepaid easily. There may be some call restrictions in the first couple of years, but it is a very flexible financing. It is distributed primarily to holders of CLOs. Some insurance companies and hedge funds buy term B loans as well. They are sub-investment grade, around BB. The term B loan market was very active before the economy crashed in the fall 2008. It has come back quite a bit since then. It is very similar to the high-yield bond market: a floating-rate instrument but senior secured debt.

Term B loans are a good barometer for the true cost of capital. The reason we see bank pricing gravitating more towards the terms in the institutional debt market is because banks, for lack of a better word, were lying to themselves about their true cost of capital, and reality has caught up. You see bank pricing gravitating to where the B loan market is.

MR. KATZ: What is the pricing difference between a B loan and a senior secured term loan from a bank?

MR. RANDALL: A BB credit probably has to pay 350 to 450 basis points over LIBOR in the B loan market. A project finance bank loan, which is usually a BB+ finance credit, is gravitating around 300 basis points over LIBOR right now. There are also upfront fees.

MR. EMMONS: We have seen B loans often applied to holding companies. If a developer has a long-term power contract, it can generally get full leverage at the project level, so there is no room for another mezzanine debt tranche. However, developers borrowing against portfolios of projects borrow at the level of a holding company one tier up from the project companies and secure the B loan by pledging the equity interests in the project companies.

MR. RANDALL: Three years ago, we had 40 or 50 banks to whom we syndicated debt. Last year, 25 banks did four or more deals. That was our definition of active. This year the list is about 15. We are seeing the bank market shrink. Usually, when you see that amount of liquidity leaving the market, you would see pricing increase dramatically. I think what offset that is that we have some Japanese and Canadian players and a couple of regional US banks coming in.

Demand is down at the same time. It is hard for developers to persuade utilities to sign long-term power contracts. We are not seeing the volume in projects that we usually do. North American project finance is around a $30-to-$40 billion-a-year market. This year, it will probably be around $20 billion.

I think demand will recover for project finance debt in a couple years. That demand will have to be filled from some other pool of capital that needs to form. Times like these see new pools of capital form, so it will be interesting to see whether the additional capital will come from the B loan market. There has been resistance to single asset financing from that market.

Private Equity

MR. KATZ: People would like to raise more money from infrastructure funds to fill in the equity portion of the capital structure. Yet a lot of private equity funds do not seem to match up well with renewable energy assets. Do you agree with that perception, and why is there a mismatch?

MR. MORALES: The private equity funds have high hurdle rates to meet, and the perception is that they usually cannot make the numbers work.

MR. SCOTT: Most of the infrastructure funds with whom I have dealt are most interested in assets with predictable cash flows. This is not what one finds in renewables projects. The infrastructure funds are used to looking at long-dated infrastructure assets, social infrastructure and transportation infrastructure. It takes time to get comfortable with resource risk.

MR. RANDALL: These private pools of capital have had to adapt to the current phase of the market. Before 2008 when renewables were booming, there were opportunities for private equity shops to make money by investing in developers and benefiting from their growth. They could benefit from rollups that would, in many cases, be sold to European investors. Basically the cycle is now reversed. Now you have a number of European investors selling off their portfolios. Returns on capital of 30% or more are just not available in at least the volume that they used to be. We are seeing some private equity shops in a sense morphing into infrastructure funds. I think a lot of them may not admit that they are looking for high single-digit or low double-digit returns, but that is what is available these days with a maturing pool of assets. The big returns are just not available like they used to be.

MR. KATZ: Carl Morales, Sumitomo does lease financing, which is a form of raising equity. Could you talk about the pricing of that product and whether you can combine it with other pieces of a traditional capital structure like debt?

MR. MORALES: The bank has tax capacity, and we are looking to deploy it. The returns are equivalent to returns in partnership flip transactions. Our focus is on single-investor leases where the lessor pays full value for the project using equity. We are not crazy about leveraged leases in project finance transactions because we are behind a lender in the capital structure.

MR. KATZ: Switching gears, there is a perception that a lot of European investors or maybe even Asian investors have a preference for US-dollar-denominated assets. Do you see that happening? How does that translate into pricing or tenor for any piece of the capital structure for power assets?

MR. RANDALL: There was talk a couple years ago that Asian investors were looking to invest in the US. We spent a lot of time in Japan and other parts of Asia looking for investors, but it became a very crowded field with many others also searching for such investors. It is hard to find Asians willing to lend. There is more interest in investing equity. Asian investors want contracted projects with long-term power contracts with creditworthy utilities. Returns for such projects have fallen to the high single digits. Infrastructure funds that had been funding highways and bridges have started looking at energy as well. This has put further */ continued page 22*

IN OTHER NEWS

megawatts have also been named as preferred bidders. These projects are made up of nine solar projects with a combined capacity of 417 megawatts, seven wind farms representing 562 megawatts and one 50-megawatt concentrated solar project. These projects are required to achieve financial close by December 13, 2012. Although the official line is that this deadline will be maintained, a delay is widely expected due to the delay in closing round 1 projects.

The round 2 projects were characterized by a significant reduction in bid tariffs compared to round 1. This was most notable among the solar photovoltaic projects, highlighting the extent to which the round 1 projects had benefited from the above-market tariffs under the program. Average prices of solar photovoltaic projects fell from 2.75¢ per kWh (SA rand) in round 1 to 1.65¢ per kWh (SA rand) in round 2.

The next round of bidding is currently scheduled for October 1, 2012, although once again it is widely expected that this date will slip.

Some 1,300 megawatts of capacity remain available for allocation under the first phase of the program, although Energy Minister Dipuo Peters recently announced that she would be issuing a further declaration "soon" extending the amount of capacity to be procured in the first phase beyond the 3,725 megawatts already in process.

THE US DEPARTMENT OF JUSTICE is expected to issue new guidance on the Foreign Corrupt Practices Act by October.

The Foreign Corrupt Practices Act makes it a crime for US citizens and companies to offer anything of value to a foreign official or official of an international public organization in an effort to win or retain business or secure any improper advantage. Foreign companies that raise equity in US capital markets are also subject to the statute.

The guidance is expected to address who is considered a "foreign official." A US appeals court is considering whether */ continued page 23*

Lowest Cost Capital

continued from page 21

downward pressure on returns.

The price of debt has increased to 5% to 6%. At the same time, equity returns have compressed to 8% to 9%, so you have a low spread between debt and equity, but you still have a huge difference in risk between the two positions. If you start to talk about merchant energy or anything that adds risk, a lot of that equity disappears pretty quickly. It is not just Asian investors, it is also infrastructure funds and sovereign wealth funds who disappear, so we see a lot of people cancelling the debt because they cannot find the equity, even for fully contracted projects. Consider in addition that there are not a lot of projects with long-term power contracts coming to market.

In 2011, 25 project finance banks did four or more deals. Only 15 are expected to do so in 2012.

Merchant Risk

MR. KATZ: Is it possible to get any form of financing on a merchant project? If not, what happens in a market where there are not a lot of contracted projects?

MR. RANDALL: As the renewable energy market starts to tail off, we are starting to see new activity on the thermal side. We see some gas-fired projects with merchant components to them. We will not see a return to the period before Enron went bankrupt where banks were financing purely merchant projects. However, a quasi-merchant project may be finance-able in an established market with a good track record. The transaction will work only if there is low leverage and maybe some level of hedging. With $2 gas, it is inevitable we are going to build more gas-fired power plants. Only a subset of lenders will consider projects with merchant risk.

MR. KATZ: Will the banks on this panel lend to a thermal project where not everything is fully contracted?

MR. MORALES: To be perfectly honest with you, we will not. Although we have done it before, we do not have an appetite for merchant risk at this time. From a risk management perspective, our institution is not comfortable with the non-contracted risk. We are not willing to make a credit decision on a "story." At least for now, we are looking only at fully contracted projects and no merchants.

MR. EMMONS: We only do renewable energy projects and, within the renewables category, we avoid market price risk which is the same thing as saying we will only lend against contracted revenues.

MR. KATZ: There are times in the cycle when banks are willing to finance merchant projects. What happens that changes their minds? Is it that you run out of contracted projects to finance or your funding sources loosen up? What would have to happen to change your minds?

MR. EMMONS: The last time banks lent against merchant projects was more than 10 years ago, and there was a lot of blood on the floor as a result. The reason for the last foray into merchant was there were a lot of fully-staffed banking groups with nothing else to do coupled with a lot of irrational exuberance. A lot of money was lost. The banks have not forgotten that. There are very few banks who will lend merchant.

MR. KATZ: Dan Reicher wrote an op-ed piece in the *New York Times* recently pointing out that renewable energy is at disadvantage because it does not have access to retail investors like the oil and gas industry has with master limited partnerships and the real estate industry has with real estate investment trusts. Are a lot of people talking about opening renewable energy to retail investors? What would that do to pricing if those markets could open up?

MR. RANDALL: There has been talk for several years now about using MLPs or REITs. However, use of MLPs requires a statutory change by Congress and people see such a change as an uphill battle, especially in an election year. For quite a while, people in the industry have said if you can get those tax credits in the hands of retail investors, then the market would become much more efficient. I believe that, too. The efficiency will drive down the cost of tax equity. MLPs would simplify a lot of the capital structure.

MR. KATZ: Putting aside the tax piece, if you could raise money against the cash flows using MLP or REIT structures, do you think that would be a game changer for the industry? Would it bring down the cost of capital significantly?

MR. RANDALL: If you are planning to use such a structure to finance a single asset, I do not think it will have a big impact. You sell the first loss layer to a tax equity investor. The MLP equity is behind other pieces of the capital structure. This will not affect the cost. Where I think you get some effective pricing is when you start to do stuff on a corporate basis. You put a bunch of assets together in an MLP and go leverage them on a corporate basis. That is where you get some real efficiencies by moving out of single asset nonrecourse structures.

MR. KATZ: Let me ask a general tax equity question because tax equity remains an important piece of the capital structure. Do you think pricing will move up or down over the next year or two?

MR. RANDALL: I think we are going to see some new entrants, including ourselves. Some regional banks are looking at investing tax equity. Developers have been trying to tap the corporates and I think with the right structure, you might see some more of them entering the market. Yield is the main driver for people.

New Trends

MR. KATZ: Where do you think you will be spending your time over the next 18 months? What new trends do you see in the market?

MR. RANDALL: In terms of lending, I think we will be spending a lot of time on M&A. I expect M&A will be where we spend most of our time on the advisory side, too. With so much equity chasing projects, we are starting to see more M&A activity. A lot of European companies are going home and liquidating assets. If you own assets, it is not a bad time to sell. I also expect to see more new construction of thermal power plants. There are going to be some interesting structures around quasi-merchant risk.

MR. SCOTT: I might echo the gas build situation in the US. I expect to see continued activity in the wind sector, especially in the south, but at a lower level than in the past. Sponsors, certainly some of the European sponsors, who have amassed a critical mass of assets in the US, will be beginning to look to refinance those on a portfolio basis or in quasi-corporate transactions. There will be much more activity in mid-stream gas assets. There has been a / *continued page 24*

IN OTHER NEWS

employees of the government-owned telephone company in Haiti are foreign officials in a closely-watched case called *United States v. Esquenzai*. Two Terra Telecommunications Corp. executives were given long prison sentences — 15 years for the company president and seven years for a company vice president — for participating in a scheme to bribe Haiti Telco employees. As many as 60% of FCPA enforcement actions are based on the position that government-owned enterprises are instrumentalities of the government.

The US Chamber of Commerce has also been lobbying for an affirmative defense for companies with strong compliance programs.

PROJECTS ON US INDIAN RESERVATIONS qualify potentially for tax-exempt financing using "tribal economic development bonds."

Congress authorized $2 billion in such bonds as part of the broader economic stimulus measures that were enacted at the start of the Obama administration in February 2009. The IRS allocated all $2 billion in bond authority in 2009 and 2010, with a deadline for the tribes receiving the authority to issue the bonds by the end of 2010. The IRS extended the deadline three times through March 2012. To date, only $197.2 million in bonds have been issued.

The IRS said in a notice in July that the remaining $1.8 billion in authority will be reallocated. There is no deadline to apply. The agency said it will consider requests for the bond authority on a rolling basis. The instructions for applying are in Notice 2012-48.

ADVANCED COAL power plants and gasification projects can apply for $685.5 million in federal tax credits.

Applications are due at the US Department of Energy by October 15, 2012 and at the IRS by February 15, 2013. The applications are submitted in two parts. The credits are 30% of the project cost. They are credits that were forfeited by developers after being originally allocated them as part of $1.3 billion in / *continued page 25*

Lowest Cost Capital

continued from page 23

fundamental change in the direction in which liquids and gas move around the US. There is growing activity in selected countries in Latin America.

MR. EMMONS: There is no one category that is going to be a big growth area, but if production tax credits are not renewed by Congress, then on-shore wind will wane. If the tax credits are renewed, then I think on-shore wind will remain a major area of focus. Mid-size, commercial and industrial solar will be a growth area because that market will continue to benefit from tax subsidies and the market penetration of PV is still low. Offshore wind will never be a huge sector, but hopefully there will be a few large deals over the next few years. We hope to be active there, but it will not be a huge segment of the market.

MR. MORALES: We will continue to push our core debt business on the project finance side and try to grow the tax equity business. We have a strong interest in doing export credit agency transactions. We have a very strong Latin American presence, so that will be an area where we also expect to see growth. ◎

Prepaid Power Contracts

by Keith Martin, in Washington

Developers are taking another look at prepaid power contracts as a way of reducing the cost of capital for utility-scale renewable energy projects.

The concept is simple and is not necessarily limited to use in the United States. The developer asks the utility that has signed a long-term contract to buy electricity from the project to prepay for a portion of the electricity in exchange for a discount on the electricity price.

Chances are the utility has a lower cost of capital than the project has. The prepayment is economically equivalent to a loan to the project by the utility that the project repays in kind by delivering the prepaid electricity. However, it is "soft" debt without all the tight default triggers that one normally finds in project debt. If there is a shortfall in electricity delivered compared to what was promised, the project can have as many as three years to make up the shortfall before there is a default, and its penalty after that is simply to pay the cost of replacement power.

At least four large wind farms with prepaid power contracts have been financed to date. In three of the projects, the prepayments raised roughly 50% of the capital cost of the project. Most of the remaining capital was raised in the US tax equity market. In one project, the prepayment was closer to 87% of the project cost.

The utilities in the four large transactions to date were municipal utilities or electric cooperatives. However, the strategy can also be used in projects that sell to investor-owned utilities and in large inside-the-fence projects.

Precedents

Municipal gas utilities have used prepaid gas contracts since at least the 1990s to make advance purchases of multi-year quantities of natural gas. The utilities issue tax-exempt bonds to raise the money for the prepayments. They see the transactions as a form of hedging to lock in long-term gas supplies at low prices during periods when gas prices are expected to rise.

At least 33 gas prepayment bonds worth $23 billion have been issued since 2003 when the Internal Revenue Service made an exception to arbitrage restrictions that were an impediment to such bond issuances. The tax-exempt bond market is supposed to be limited to financing of roads, schools, hospitals and other public facilities. A municipality cannot borrow in the bond market at tax-exempt rates and then invest the bond proceeds in a way that earns a higher return, as that would increase bond volume and push up rates to finance public facilities. US tax regulations define impermissible arbitrage as including borrowing to purchase commodities. However, in 2003, the IRS made an exception in the arbitrage rules to permit prepaid gas and electricity transactions.

Under the IRS regulations, no arbitrage profit will be found where a municipal utility prepays for electricity as long as the municipal utility uses at least 90% of the electricity to supply retail customers in its historic service territory or to make wholesale sales to other municipal utilities that use the power to supply their own retail loads. A utility's historic service territory is the area it served at all times during the five years leading up to when the tax-exempt bonds were issued.

In August 2005, Congress wrote a slightly different version of the exception for prepaid gas deals directly into the US tax code as part of the Energy Policy Act of 2005. The statutory exemption only covers gas; Congress was silent about electricity. A Treasury official told Chadbourne at the time that he did not believe there was an intention to rule out prepaid electricity transactions and they can still be done under the exception in the IRS regulations.

Prepaid gas transactions are centered around the municipal bond offering. The gas supplier is usually a commodity unit of a large bank or investment bank that guarantees performance by the supplier, allowing the bonds to have the same credit rating as the bank or investment bank providing the guarantee. Credit downgrades for 15 banks in June 2012 led to a cut in ratings on 24 gas prepayment bonds worth about $19 billion.

Three electricity prepayment deals were done during the period 2003 through 2007 patterned on the gas model. Of these, the longest was a $1.4 billion purchase of six years' of electricity by Memphis, Light, Gas & Water from the Tennessee Valley Authority in December 2003. Fayetteville, North Carolina entered into a two-year deal in November 2005. American Municipal Power-Ohio signed a six-year deal with J. Aron, a Goldman Sachs subsidiary, as the supplier in 2007.

In transactions using the gas model, the municipal utility pays in advance for all the gas or electricity it will be delivered over time.

The first prepaid electricity deal involving a wind farm closed in December 2006. The offtakers were two public utility districts and two electric cooperatives. No municipal bonds were issued to finance the prepayment. Such bonds were issued in the next three transactions, but unlike the gas model, they were not a central focus.

PPA Terms

Under the structure as adapted for use by independent generators, the utility prepays for only a portion of the electricity to be delivered.

The structure works as follows.

The utility enters into a long-term contract to buy electricity. It pays at closing on the permanent financing for electricity to be delivered over the full term of the contract. The contract has a schedule showing the quantity of prepaid electricity each year. For example, the schedule might show a fixed annual quantity of megawatt hours of electricity for which the utility has paid in advance. The utility must pay on a current basis for any "excess" electricity the project delivers above the prepaid quantity as well as for any renewable energy credits, carbon credits and other intangibles. It can only prepay for electricity; thus, in contracts with both energy and capacity payments, the capacity payments could not be paid in advance. Sometimes the prepayment is merely a deposit against the future cost of the prepaid electricity, and an additional payment must be made as the prepaid electricity is delivered. / continued page 26

IN OTHER NEWS

allocations in 2006 through 2009.

The credits can be claimed on new IGCC (integrated-gasification combined-cycle) power plants and other power projects that use "advanced" technology to generate electricity from coal. At least 75% of the fuel used in the plant must be coal. The project must be placed in service within five years after credits are awarded. Projects receiving awards will be notified by May 15, 2013. Details are in Notice 2012-51.

BRAZIL said in June that it will limit collection of a 6% financial transactions tax, called the IOF, to loans of up to two years. Brazil increased the tax rate from 0.38% to 6% and extended the tax to loans of up to five years in March in an effort to discourage short-term dollar inflows that were hurting exports by causing the real to appreciate against the dollar. The government reversed course three months later after deciding it was more important to make it easier for Brazilian companies to borrow from foreign banks. The European financial crisis has caused a number of banks to withdraw from the market.

Meanwhile, BNDES, the Brazilian development bank, has suspended loans to purchase wind turbines that do not meet domestic content requirements. Turbines made in Brazil do not qualify for BNDES financing unless at least 40% of the components are made in Brazil.

ARGENTINA said in July that it is terminating its tax treaty with Spain effective at year end. It announced earlier in the year that it is terminating tax treaties with Chile, Austria and Switzerland. It said it hopes to negotiate new agreements that prevent companies from taking advantage of "loopholes" in the treaties.

MAURITIUS remains under pressure from India to modify a tax treaty between the two countries. The treaty lets Mauritius companies holding shares in Indian companies avoid capital taxes when the shares are sold. / continued page 27

Prepaid Power Contracts

continued from page 25

In most transactions, the utility receives a discount on the prepaid quantity for having paid in advance.

The utility has a first lien allowing it foreclose on the project in the event the project defaults on the obligation to deliver the prepaid electricity. However, the project usually has three years to make up any shortfall before it is considered in breach and even then it is required to pay a cost of cover before the situation turns into a default.

The utility usually has an option to purchase the project at year 10 and again at the end of the power contract for fair market value determined upon exercise. The value is whatever the parties agree at the time or, failing agreement, what an appraiser concludes is the value. The value at year 10 is calculated by assuming the project will continue to benefit from or remain burdened by the remaining term of the power contract so as not to create any economic compulsion for the utility to exercise the option.

Limit on Prepayment

There is a limit on the size of the prepayment.

It is important that the developer not have to report the full prepayment as taxable income upon receipt. Companies must normally report cash payments from customers as taxable income no later than when the amounts are received. However, the IRS regulations have a special rule for advance payments to manufacturers of "goods." Advance payments may be reported as the goods are delivered, provided the manufacturer reports them no more rapidly "for purposes of all his reports (including consolidated financial statements) to shareholders, partners, beneficiaries, other proprietors, and for credit purposes."

In the case of "inventoriable goods," a two-year clock begins to run on when the remaining advance payment must be reported as taxable income when two things are true. One is the manufacturer has on hand through inventory or available through his normal sources of supply the remaining quantity of goods for which the customer has prepaid. The other is the manufacturer has received a "substantial" advance payment. An advance payment is "substantial" when it equals or exceeds the expected cost to supply the goods.

The IRS treats electricity as "inventoriable goods." Thus, the two-year clock has the potential to be triggered.

It is unclear whether an independent power project will be viewed as having available to it at inception — or at any time in the future — through normal sources of supply all of the electricity that was prepaid under the power contract. There is a spot market in electricity. The project can buy at some price the full output promised over the full term of the power contract. However, that cannot be what the IRS intended by this trigger. The reason for starting a two-year clock to run is that the IRS thought it inappropriate in certain situations to tax manufacturers fully on advance payments at time of receipt, but it did not want to let manufacturers play games with timing by spreading out income when they have all the inventory needed to supply an order either sitting in the warehouse or readily accessible by picking up a phone. The typical long-term power contract calls for scheduled deliveries over a particular time period. Electricity cannot be stored. Under the IRS regulations, the two-year clock does not start to run until the producer "[h]as on hand (or available to him in each year through his normal source of supply) goods of substantially similar kind or in sufficient quantity to satisfy the agreement in such year." It would not satisfy the agreement for the project to supply the utility on day one with the full amount of electricity the utility requires over 20 years. The utility would bring a claim for breach of contract.

Two things must be true for the two-year clock to start to run. The other is that the advance payment must be "substantial." It is substantial when it equals or exceeds the expected cost to supply the electricity. The logic behind this trigger is that the United States taxes businesses on income and, until the project has received a large enough payment to lock in a profit on the electricity that has been presold, it does not yet have any income to tax.

This has a bearing on how large a prepayment can be made. The expected cost to supply the electricity includes depreciation on the power plant. The expected costs to supply electricity should be allocated among all of the output. The test whether the prepayment is substantial should be applied by comparing the prepayment only to the costs that are allocated to the prepaid electricity.

If the remaining advance payment must be reported in full as income because of the two-year clock, then the project would have to report only the net amount after subtracting its expected cost to supply the remaining prepaid electricity.

The special IRS rules for advance payments have an interesting history. Section 452 of the US tax code — since repealed — allowed accrual taxpayers to elect to report prepaid income over the period it is earned. The section was enacted as part of the

US tax code in 1954, but was retroactively repealed in June 1955 after Congress decided that the revenue loss would be many times greater than what was originally projected by the Treasury Department. The repeal was interpreted by the IRS and the courts as a direction from Congress that deferral of prepaid income would no longer be allowed. Three subsequent Supreme Court decisions during the period 1957 through 1961 — two involving automobile clubs and one a dance studio — confirmed that prepaid income had to be reported by an accrual taxpayer when it is received.

The Supreme Court cases dealt with payments for services, but created uncertainty about the effect of prepayments for goods. Some taxpayers worried that the decisions would require advance payments for goods to be reported immediately as income while the cost of goods sold would not be deductible until a future year.

In 1970, a presidential task force on business taxation recommended that the Treasury use its administrative authority to try to achieve greater conformity between taxable income and book income reported under US generally accepted accounting principles or GAAP. The IRS proposed the special rule for advance payments the same year. In February 1971, the IRS released a technical memorandum responding to comments that had been received from the public about the proposed advance payment rules. The memorandum said the accelerated inclusion rule for inventoriable goods was included "to prevent manipulation (lengthening the deferral period) by failure to deliver goods when the taxpayer has received substantial advance payments and has sufficient goods on hand to satisfy the agreement." It said abuses of this kind were unlikely to involve goods that are not inventory. Presumably the problem with inventoriable goods is their fungibility invites manipulation by a factory with lots of orders to fill. The regulations were republished in final form the following month.

The reason for waiting to start the two-year clock until advance payments exceed the expected cost to supply the goods is that the tax laws tax income. Until that point, the manufacturer has a loss — not income. After that point, any further payments received are income.

IRS regulations require that the remaining advance payments be reported as income if the company that owns the project "ceases to exist" or if its liability under the power contract otherwise ends. Therefore, the unamortized portion of the prepayment would have to be reported as income if the purchase option is exercised by the utility before */ continued page 28*

IN OTHER NEWS

The two governments held bilateral talks again in late August on revising the treaty. India wants Mauritius companies to have more substance in order to benefit from the treaty.

The uncertainty is harming the economies of both countries, the Mauritius finance minister said.

Forty-two percent of investment into India during the period 2000 through 2011 went through Mauritius companies. The trade in offshore companies accounts for 5% of gross domestic product in Mauritius. India is particularly upset about "round tripping" where Indian residents circle investments in Indian companies through Mauritius to avoid capital gains taxes upon exit.

The Authority for Advance Rulings in India continues to respect the treaty in the meantime. It held in at least three cases in July and August that Mauritius companies could not be taxed on capital gains. The tribunal said that it did not matter that the capital gains will go untaxed in Mauritius.

Mauritius is targeting new business with Africa, where it has double taxation treaties with Botswana, Lesotho, Madagascar, Mozambique, Namibia, Rwanda, Senegal, Seychelles, South Africa, Swaziland, Tunisia, Uganda and Zimbabwe. Treaties with the Congo and Zambia are awaiting ratification, and treaties with Egypt, Ghana, Kenya, Malawi and Nigeria are awaiting signatures.

Meanwhile, China rejected a claim by a Chinese foreign joint venture that dividends paid to a joint venture partner in Mauritius qualify for a reduced withholding tax rate of 5% under the Mauritius-China tax treaty. (Chinese withholding taxes on dividends are normally 10%.) The authorities concluded that the Mauritius company was merely a front for the real investor in another country because it had no employees, carried out no real business in Mauritius and had only $9.81 million in registered capital but invested $150 million in the joint venture, and only two of seven board members were domiciled in Mauritius.

/ continued page 29

Prepaid Power Contracts

continued from page 27

the term of the power contract ends. There is also a risk of accelerated reporting if the project company is a partnership for tax purposes and it terminates for tax purposes because of a sale of 50% of more of the profits and capital interests in the partnership.

In order to qualify as an advance payment, the power contract should require that the unamortized portion of the prepayment be returned if the contract terminates due to fault of the project company. The contract should include a schedule showing the quantity of electricity that has been prepaid each year. Because tax deferral is allowed only for advance payments for "goods," the prepayment should only be for electricity. Any renewable energy credits, environmental allowances or other intangibles that will convey to the utility should be paid for as they are delivered.

The IRS is studying the tax treatment of prepaid forward contracts and may have more to say in the future about the timing for reporting the prepayment. In January 2008, the agency issued a revenue ruling analyzing the tax treatment of a forward contract for which the holder paid $100 on January 1, 2007, at a time when $100 was worth €75, requiring delivery to the holder of €75 plus a return three years later on January 1, 2010. The instrument paid the holder the dollar equivalent of €75 plus a compound stated rate of return, with conversion into dollars occurring at the exchange rate on January 1, 2010. The IRS said the instrument was in substance a euro-denominated loan by the holder to the issuer. The IRS said in a separate notice the same day that it is studying the tax treatment of prepaid forward contracts and it asked for comments on a list of questions, including whether the seller under a prepaid forward contract that is in fact a forward sale, rather than a loan, should be required to accrue income during the term of the forward contract and, if so, how the amount of income each year should be calculated.

Foot Faults

Extra care must be taken in most prepaid power contracts to ensure that the contract will be treated by the US tax authorities as a true power contract rather than a lease or installment sale of the power plant or a partnership with the utility. The problem if the contract is not a power contract not only in form, but also in substance, is that tax benefits on the project could be lost to the developer. The US government provides tax subsidies to wind, solar and other renewable energy projects worth at least 56¢ per dollar of capital cost.

Developers are looking at prepaid power contracts as a way of reducing the cost of capital for utility-scale renewable energy projects.

The power contract should say the parties intend it to be a "service contract within the meaning of section 7701(e)(3) of the Internal Revenue Code." It should also be drafted to avoid four "foot faults."

The four foot faults are as follows. First, neither the utility nor any of its affiliates can operate the project. Second, the utility cannot bear any "significant financial burden" if the project fails to perform (other than for reasons beyond the control of the project owner). This means basically that the utility should not be required to pay for electricity it does not receive. Third, it cannot receive "any significant financial benefit if the operating costs . . . are less than the standards of performance or operation under the contract." This means the project cannot share any savings it achieves through introduction of technological or operating efficiencies with the utility. Finally, neither the utility nor any of its affiliates can have an option to buy the project at a "fixed and determinable price (other than for fair market value)."

Many US renewable energy projects are financed in the tax equity market. Such projects need to set the option price in practice at market value but not less than the amount the tax equity investor requires to reach its target yield. This may require referring to a termination value schedule. In one transaction with tax equity investors worried about violating the purchase option foot fault, the option for the utility to buy the project at the 10-year point in the contract was structured as an option to buy at fair market value, but the project owner could refuse to sell if market value was not at least the amount required to reach the tax equity yield. In the event of a refusal, the option would roll over to the next year, and so on, until the option either goes unexercised in a year or the market value is the higher of the two amounts. However, this is more complicated than is required. One utility has insisted on symmetry: if the option price has a floor, then it wants a cap. Such a "collar" raises questions whether the price is too close to a fixed price. Tax counsel have gotten comfortable by concluding that the ceiling and floor prices are so far out of the money that neither is expected to come into play in practice. The wider the band is above and below the option price, the better.

Another practical issue in deals is whether any of the operating costs of the project can be passed through to the utility under the contract. A straight pass through of all operating costs raises issues whether the utility will bear a financial burden if the project fails to perform or will benefit if operating costs are reduced. Most tax counsel are fine with a pass through of such things as property taxes and insurance premiums that are not tied to output.

Failure to avoid the foot faults is not the end of the world. Avoiding them ensures that a power contract to sell output from a cogeneration or alternative energy facility will be treated for tax purposes as a power contract rather than a lease of the project to the utility. It may still be possible to prove by other means. However, most tax equity investors prefer to play it safe.

Other Considerations

Use of a prepaid power contract will make tax equity more expensive. Tax equity investors have tended to view the prepayment in tax equity transactions structured as partnership flips as equivalent to debt and required a yield premium. The premium runs to 700 basis points in the current market. It was 250 to 300 basis point before the economy crashed in late 2008. ◎

IN OTHER NEWS

A TAX OPINION cannot be relied on to avoid IRS penalties if the lawyer writing the opinion helped promote the transaction and receives fees that are tied to the tax benefits produced. The conflict of interest makes the opinion unreliable, the US Tax Court said in *SAS Investment Partners v. Commissioner* in June.

FOREIGN TAX CREDITS may soon be at issue in a case before the US Supreme Court.

PPL Corporation, the parent company of a Pennsylvania utility, asked the court in August to hear an appeal of whether the utility could claim windfall profits taxes it paid in the United Kingdom, after buying a privatized regional electric utility, as a credit against its income tax liability in the United States. The US allows foreign taxes to be credited, but only if they are income taxes in a US sense. The IRS has argued that the taxes are not creditable based on a reading of the UK statute. The IRS won on appeal in its dispute over the taxes with PPL Corporation, but lost in a similar case involving US utility Entergy, which had to pay windfall profits taxes on its shareholding in London Electricity. Both taxpayers won in the US Tax Court, but the cases were appealed to appeals courts in different parts of the United States based on where the taxpayers are located.

PPL argues that the IRS should look at the underlying substance of the UK tax rather than focus narrowly on the words in the UK windfall profits tax statute.

The British government collected a one-time tax on the "windfall profits" that the owners of the privatized utilities earned due to the initial bump up in share prices after privatization. The tax had to be paid in two installments in 1997 and 1998. The tax was 23% of the appreciation in value of each utility since privatization. The appreciation was calculated by comparing the amount paid for the shares at privatization to the company's "value . . . in profit making terms" in 1997. This was defined as nine times the company's average annual / continued page 31

The Rush Into Latin America: Are Developers Making Money South of the Border?

A slowing market on the US mainland has sent developers scurrying into Mexico, Brazil, Chile, Peru and Puerto Rico, among other locations. Do these projects make money? What are the economics in these markets? What is the market potential? What are the main pitfalls compared to developing and financing projects on the US mainland and in Europe?

Two developers and two investors who are active in these markets shared their experiences at the Chadbourne global energy and finance conference in June. The panelists are Lachlan Creswell, a managing director of Macquarie Capital Mexico, Kim Oster, director of Latin American development for First Solar, Lars Peter, a director with T-Solar Global, and Alok Garg, a director with Scotia Capital. The moderator is Rohit Chaudhry with Chadbourne in Washington.

MR. CHAUDHRY: Kim Oster, First Solar has been one of the most active solar developers in the United States. However, First Solar now seems increasingly focused on opportunities outside the US, including Latin America. What is driving this increased interest in Latin America?

MS. OSTER: We are really focused on markets that are sustainable, and electricity prices and demand for electricity are high in a number of countries in Latin America. These are ideal places for solar photovoltaic projects. Solar panel prices have fallen dramatically over the past few years, and this has been a game changer. We are starting to see places where we can compete head to head with other sources of electricity.

MR. CHAUDHRY: Lars Peter, is the interest of T-Solar in Latin America driven by attraction to the Latin American markets or are the head winds in the US renewables market driving some of that interest?

MR. PETER: The move into Latin America is not that closely related to the difficulties in the US market. We are a Spanish company; language and culture are not barriers to working in Latin America. The main reason for the move is the availability of the resources. If you look at Peru and the north of Mexico, there are really interesting spots where you have a lot of solar and wind resources. Some of those countries like Peru, Mexico and Chile came up with some really interesting regulations that create an opportunity to invest in solar PV. There are not many good markets left in the world. We are being driven out of the markets in Europe; if you look at a world map, you see that the US is still a viable market and what comes next is a move into Latin America.

MR. CHAUDHRY: Lachlan Creswell, Latin America lacks the potential scale of the markets in the US, Europe and Asia. Am I wrong? Do you see a big boom in renewables coming soon in Latin America? Has it already started?

MR. CRESWELL: In the case of Mexico and Brazil, it is well and truly underway. Brazil has just passed 1,000 megawatts of installed capacity, which is nothing compared to the US. The total installed capacity in Mexico is significantly smaller. There is certainly lots of space to move into for the renewable sector. There are great solar and wind resources, and the early projects are taking advantage of these very high-quality resources. Resource mapping is still at a relatively early stage. Good maps will create further opportunities as the sector matures.

MR. CHAUDHRY: Alok Garg, as a lender, do you find yourself shifting focus to Latin America? Do you see the boom now or is it premature?

MR. GARG: We see a tremendous number of opportunities in Latin America. Scotia Bank has an extensive presence in Latin America; we have significant local banking networks. As our clients exhaust the opportunities in the US and the returns are driven down, they start to look at opportunities where there is more country risk and more regulation risk, and that tends to give you higher returns. They are going south of the border, and we are following them.

Specific Markets

MR. CHAUDHRY: Lachlan Creswell, getting into more specific markets as opposed to Latin America as a whole, which countries in Latin America do you find more interesting and why? You are based in Mexico City, so Mexico is an obvious example.

MR. CRESWELL: Mexico is interesting because of its scale within Latin America. The regulatory regime for independent power projects makes it an attractive spot to continue to focus. There are interesting opportunities in Chile with similar dynamics in that you have a very well understood regulatory regime; you have US dollar-based contracts and a high cost of power because of structural elements within that market. The country depends on imported fuels. If you can get a good resource, be it solar or wind, you will be competitive, particularly given some of the other pricing dynamics in the Chilean market.

Brazil certainly has lots of potential; it is a huge market and has lots of great natural resources. However, the local content requirements and the auction-driven approach to issuing power purchase agreements for renewables make that market a little more challenging for us.

MR. CHAUDHRY: Kim Oster, which markets in Latin America is First Solar focused on, and why?

MS. OSTER: We are focused on Chile where you have strong solar and wind resources, no internal source of fuel, high electricity costs, access to low cost financing, PPAs that are dollar denominated, offtakers with great credit and clear environmental laws. We are also focused on Mexico because of the high price that we see from the industrials and a high solar resource in some areas. There are lots of opportunities in theory in Brazil. It is a large and growing market and there are areas in the northeast that have a high solar resource, but the utility-scale market barely has yet to open up, and there have been no federal options.

Wholesale Electricity Prices

MR. CHAUDHRY: Lars Peter, I am eager to hear about the kinds of wholesale prices you see on offer to renewable energy developers in the four markets to the extent you can share it: Chile, Peru, Mexico and Puerto Rico.

MR. PETER: Puerto Rico is amazing. Retail electricity prices are very high, making solar cost competitive. Mexico is on the verge of bringing out a new energy regulation; the first prices we have seen are around $200 a megawatt hour.

We have installations in Peru where we get $180 to $220 a megawatt hour, but it is just the first round, and they have already had the second round bids and awarded some contracts at a lower price around $120 a megawatt hour. It is getting tougher to be competitive there.

We had a look at Chile. You can get private contracts from the mining companies that are coming in with prices around $200 a megawatt hour. You need to be one of the first movers; otherwise you lose out as we saw in Peru. Prices have tended to decrease dramatically over time.

/ continued page 32

IN OTHER NEWS

after-tax profits in the four years immediately following privatization.

Only "income taxes" may be credited. The IRS argues that the UK windfall profit tax fails because it was a tax on hypothetical appreciation in value of the regional utilities — rather than on actual gains — and the British government did not wait to collect the levy until the shareholders "realized" their gains by selling shares.

CARBON CREDITS did not have to be reported as income by a US real estate investment trust.

The REIT invests in timberland. Some of its investments are in a foreign country. It holds these investments through an offshore holding company. The country awarded carbon credits for owning forests that serve as a "sink" for absorbing carbon dioxide. The IRS said in a private letter ruling made public in July that a company receiving carbon credits from a government does not have to report the value as income upon receipt.

A later sale of the credits would trigger income. However, any sales proceeds in this case would not have to be reported in the US until the earnings are repatriated. The agency said they are not considered a form of passive income — called "subpart F income" — that the US would look through the holding company and tax without waiting for the income to come back to the United States.

The ruling is Private Letter Ruling 201228020.

DEVELOPERS who receive interests in projects in exchange for ongoing services should consider making a section 83(b) election to pay taxes on the interest upon receipt rather than waiting for it to vest fully.

Most power projects in the United States are owned by limited liability companies that are treated as partnerships for US tax purposes.

There are two kinds of partnership interests. A developer could receive an interest solely in partnership profits, or it could receive a capital interest that entitles the developer to a share of the asset value when the partnership liquidates. A developer receiving

/ continued page 33

Latin America

continued from page 31

MR. CHAUDHRY: In Peru, you mentioned in this second round the price is down to $120 a megawatt hour. At those prices, does Peru remain an interesting market for you?

MR. PETER: Yes, absolutely, because if you look at the irradiation map, there is 50% more irradiation than in southern California.

MR. CHAUDHRY: Puerto Rico is another strong market for renewables. The number of wind deals and solar deals that people seem to be doing there is disproportionately higher than what one would expect given the population. Is it purely prices, or are there other factors driving interest in Puerto Rico?

MR. GARG: The retail price for electricity is about 20¢ per megawatt hour. Puerto Rico is a US territory, so you still get all the tax incentives that you get on the US mainland. It is a dollar-denominated country. You are not dealing with significant regulatory risk. The local distribution company has learned how to do these projects, and interconnections have been more forthcoming.

Developer Rates of Return

MR. CHAUDHRY: What rates of returns do developers typically expect in different markets? Let's start with Puerto Rico.

MR. GARG: It is question of what kind of cost structure in the awarded PPAs. Developers have bid unleveraged returns in the mid-teens.

MR. CHAUDHRY: Lars Peter, what kind of returns do you expect?

MR. PETER: That is a difficult question. You need up to two years to get a solar project done. You need additional returns to compensate for the period at risk. Permitting is really hard. There are hidden costs that do not become apparent until after development is well underway. Developer returns are probably in the range of 15% to 18%.

MR. CHAUDHRY: Kim Oster, how do the returns that people are expecting from projects in Latin America compare with what developers would expect in from a project in the United States?

MS. OSTER: They are higher in Latin America. We have also found that local investors evaluate projects differently than the US. For example, in Chile we see a focus on real return on assets versus return on equity. The returns are definitely starting in the mid- to high teens.

MR. CHAUDHRY: Alok Garg, do you want to comment on that?

Returns on Latin American wind and solar projects are in the 15% to 18% range.

MR. GARG: In Mexico, we have seen a broad range of returns; they depend on the project structure. There are independent power projects that are basically PPAs tendered by the Comisión Federal de Electricidad in dollars. The CFE assumes a lot of the permitting risk, so you are down to a return on equity in the low double digits. In other projects where the developer bears contracting risk, permitting risk and the risk of taking control of the land, there is a lot more risk and the returns are necessarily higher.

Securing a Power Contract

MR. CHAUDHRY: An earlier panel talked about the difficulty of getting long-term power contracts for renewables, especially for wind projects. All of you suggest that the returns in Latin America are high compared to other places. How easy and what is the process for getting the PPA in these countries? Let's start with Peru.

MR. PETER: Officially, it is easy because they come out of the public bidding. When you know about the possibility, it is already late; you should know before the request for proposals is announced. This is the first difficulty. You need local people, very good and involved people in the different authorities to find out when they will come out with new bidding. You need to have a very long-term fuel supply agreement because probably the prices you expect today will not be the prices in five to 10 years. We took part in the second bid and lost because the other bidders were more optimistic about fuel costs. A track record is very important to the government.

MR. CHAUDHRY: Kim Oster, the process in Chile is very different than the process in Peru. How difficult is it to get a PPA in Chile, and what is the process?

MS. OSTER: So far the PPAs have really been led by the mining companies themselves. What we are seeing right now is that solar a real plus given the pricing on solar and we are looking at direct PPAs and bilateral negotiations with the mining companies rather than with a government office.

MR. CHAUDHRY: Kim Oster, staying with you for a second and moving beyond PPAs, you spent a huge amount of time developing Desert Sunlight, which I am sure everyone knows is massive 550-megawatt solar project in California. You were the lead developer on that. Now you are developing projects in Chile. What are the differences in developing a project in the US versus in Latin America?

MS. OSTER: Chile has a 30% higher solar resource than southern California so you are able to compete against conventional fuel without any subsidy or tax incentives. We see a lot of similarities in terms of the permitting process. California has to be the most challenging market in terms of the complexity of permitting. You see a lot of the same focus on biological and cultural resources.

MR. CHAUDHRY: Lachlan Creswell, what are the toughest challenges to developing projects in Mexico and other places in Latin America?

MR. CRESWELL: It very much varies with local conditions. In Mexico, for example, the main constraint is transmission capacity and transmission access. The state utility has run an open season for the new capacity and there is still a lot of uncertainty around timing and actual cost for installing that. More generally it is true throughout Latin America that social and community relations issues are something that all developers need to focus on pretty carefully, particularly where indigenous communities are involved in land ownership.

MR. CHAUDHRY: Lars Peter, what do you think?

MR. PETER: Environmental regulation is generally more challenging in California than in Latin America. The big issue in Latin America is real estate. It is unclear in many places who owns the land. The zoning is not clear. Most of these countries lack a long-term policy and lack much experience with alternative energy. If you're the first mover, you have to educate them and they have to fine tune the laws and fine tune the regulations, and you hit the wall every time you go there and want to move something forward, so it takes a lot of time.

/ continued page 34

IN OTHER NEWS

a capital interest in exchange for services must report the value as income after subtracting anything the developer had to pay for the interest. The interest is compensation for the services.

However, value does not have to be reported until there is nothing else he must do to earn it or, if earlier, when the developer first has a right to transfer the interest. The IRS allows the developer to choose to pay taxes upon receipt instead. This might make sense if the interest has a low current value but the value is expected to increase over time — for example, as construction of the project is completed. The developer can do this by filing a section 83(b) election with the IRS within 30 days after receipt of the interest.

The IRS released sample language for making such elections in late June. The language is in Revenue Procedure 2012-29. The election can only be made for interests that have a readily ascertainable market value.

The downside is that if the developer ends up reporting the value of an interest that never vests — for example, because the developer failed to do the full work required to earn it — then he has a capital loss, but only for any amount he paid for the interest and not for the full income he had to report.

A MANAGEMENT CONTRACT for a private company to operate the portion of the electricity grid belonging to a municipal utility will not cause loss of the tax exemption on debt the utility used to finance the equipment, the IRS said.

Municipalities can issue tax-exempt bonds to finance schools, roads, hospitals and other public facilities. The bonds allow borrowing at a reduced interest rate because the bondholders do not have to pay federal income taxes on the interest. However, a municipality must be careful not to allow more than 10% "private business use" of property financed with the bonds or the tax exemption may be lost.

It is potentially private business use to hire a private company to operate the grid. The IRS issued guidelines in / continued page 35

Latin America

continued from page 33

Financing

MR. CHAUDHRY: Let's move to financing of projects once people have surmounted these issues. We had a similar panel last year at this conference and I was surprised to hear from that panel that people said the commercial banks had barely financed any renewable energy projects in Latin America. They were chasing opportunities. The multilateral lending agencies and export credit agencies have financed a bunch of projects, but the banks were lagging behind. Is that still true? Or have the markets changed and have there been a bunch of deals financed in Latin America?

MS. OSTER: Chile is exceptional. There have been great projects that have been financed. People have been looking at hydro projects as well as wind and solar. Puerto Rico has had a number of financings close. I have not seen many other financings.

MR. GARG: The other day we were looking at the number of opportunities. There are about 20 different projects in various stages at which we are looking very seriously about financing. A lot of them will have some kind of export credit agency or multilateral lending agency involvement, but in terms of deal flow, there will be significant deal volume.

MR. CHAUDHRY: And the financing terms for these Latin American countries, how are they structured and how are they different than what you see in the US? When you're sizing your debt, what kind of leverage are you looking for and what kind of coverage ratios are you looking for to provide financing?

MR. GARG: It is not significantly different from a credit perspective looking at a deal in Latin America versus the United States. You have the same constraints: 1.0 coverage ratio at P99, 1.45 at P50 and a minimum of 20% equity. We look for a strong developer, a good resource — all the things that you would look for in the United States. What you do see, though, in Latin America, is wider variances in pricing and tenor: for example, in Peru, the pricing tends to be in the 4+% range over LIBOR; in Chile, the pricing is more aggressive. In Mexico, it is more aggressive. There are some places in Latin America where it is hard to get commercial bank funding at all.

MR. CHAUDHRY: Lachlan Crewswell, you just closed a deal, Marñea Renovables, which is the largest wind deal to close in Latin America, but that had long tenors on the debt. How do you see the bank market: what terms are being offered to you? How aggressively are banks chasing you?

MR. CRESWELL: I think we were probably a little fortunate in the terms we were offered. Roughly 14 months passed before the financing closed, and we were able to hold the basic terms through the development phase and negotiation of the final terms. I see the kind of macro-trends that were talked about during another panel discussion this morning: the impact of regulation on bank capital and banks generally looking for shorter tenors. I think that will be an increasing feature of projects going forward in Mexico. Export credit agencies will play an important role in tapping what is left of the market capacity and obviously the development banks will as well. I think people are going to be left with a choice between focusing on export credit agency and development bank money and having some commercial bank financing come alongside that, or looking at mini-perm facilities from a broader commercial bank syndicate.

MR. CHAUDHRY: In addition to bank money and agency money, there seems to be talk about project bonds in Latin America, especially in Mexico. A lot of people are trying to structure project bonds for deals, including renewable deals. How real are they?

MR. GARG: There is a lot of local institutional money in these countries that is looking for places to be deployed. In Mexico, we have seen an issuance of project bonds in connection with a bid for a gas-fired project. We have been involved in project bonds in Peru. Chile has appetite as well. So we do see a project bond appetite. The issues you face are similar to what you face in the US market. The negative funding cost of issuing project bonds during construction is an issue. Clearly you want to have some operational history to get an investment-grade rating. We are very excited about the project bond market and are actively working to develop it.

MR. CHAUDHRY: Do you see much liquidity in the local markets? Can you do local currency debt? Are there a lot of local banks that could step up for your entire project?

MR. GARG: Local banks are not usually able to tackle these deals.

Predictions

MR. CHAUDHRY: Let's end with projections. Kim Oster, what do you project for renewables in Latin America or, perhaps more specifically, solar in Latin America?

MS. OSTER: The price of PV has come down dramatically. Back in 2004, modules were at $3 per watt. Now we are looking at a projection of 55¢ a watt. That continues to be a game changer in markets where you have a high cost of electricity and a high solar resource. So we see a lot of opportunities in Latin America as we are able to compete against conventional forms of energy.

MR. PETER: There are three types of countries in Latin America. There are the ones who do not need PV resources. Brazil is an example, because it has a lot of hydroelectric power. Then you have two others: countries like Argentina where we do not go because there is no stable regulation and you cannot really trust the government, and there are countries like Chile and Peru where there are governmental trust, good resources and a good market. The focus will remain on countries in the last category, Peru, Chile and Mexico, where you can see a lot of demand.

MR. CHAUDHRY: Alok Garg, your wife is Argentinean. Do you agree with this analysis of Argentina, and what do you project? [Laughter.]

MR. GARG: I wish we had more business to do in Argentina, but our bank is not comfortable with that country. We are working on a number of opportunities. It is a tremendous amount of work, but very few closings. That is the challenge with Latin America in general. We come from a US background, where things are modularized and you can take a deal from start to finish and in three to six months have a financier whereas, in Latin America, deals just take an inordinate amount of time and effort, especially with the various funding options, including export credit agency and development bank involvement. I am skeptical whether we will see more than a handful of actual closings.

MR. CHAUDHRY: Lachlan Creswell, you have the last word.

MR. CRESWELL: A key trend we will see is the focus on high-quality resources. We will eventually hit transmission constraints, as has already happened in Oaxaca and I think we are ultimately going to hit a constraint in terms of the number of projects that can be viably developed without further incentives. We have some high-price markets in Latin America, but ultimately as the resource quality starts to disappear, unless capital costs keep falling as they have with panels and wind turbines, then you need to look at different structures or further regulatory incentives to continue to build out the renewable energy sectors in these economies. ◎

IN OTHER NEWS

1997 for municipalities to follow in drafting management contracts with private parties. A contract involving public utility property cannot run longer than 20 years or, if shorter, 80% of the expected useful life of the equipment. At least 80% of the services in each contract year must be compensated on a fixed-fee basis. No part of the fee can be tied to operating profits. A contract that merely passes through actual and direct costs of the contractor and reasonable administrative overhead is not a problem. The manager cannot have a relationship with the municipality that substantially limits the municipality's ability to exercise its contract rights.

The IRS approved a proposed arrangement to manage a municipal electricity grid that departed from these guidelines in a private ruling that the agency made public in July. The ruling is Private Letter Ruling 201228029.

The contract had a term of 10 years. The municipal utility agreed to pay the grid manager periodic fixed payments, plus incentive payments that were tied to four performance metrics, plus reimburse the manager for its actual costs.

The contract raised issues because the "fixed" fee was not really fixed. It was subject to downward adjustment to the extent the manager failed to provide credit support or performed poorly. The manager could receive additional incentive payments tied to performance metrics. It could pass through charges from affiliates with a mark up at a rate of return approved by the Federal Energy Regulatory Commission.

The IRS said none of these features is a problem because none of them is tied to operating profits.

BARGE-MOUNTED POWER PLANTS are probably not "vessels" for tax purposes.

The IRS concluded that a floating casino was not a "vessel" in an internal legal memorandum that the agency made public in June. A vessel can be depreciated on an accelerated basis over 10 years. The IRS said the */ continued page 37*

Biomass Suffers A Setback

by Paul Kaufman, in Los Angeles

Massachusetts made it harder in August, after two years of study, for power plants that use biomass as fuel to qualify for full renewable energy credits under the state's renewable portfolio standard as "class I" resources.

Renewable energy credits can be sold, and are potentially an additional source of revenue.

The decision also affects biomass projects in neighboring states. Generating capacity under the control of ISO-New England, the independent entity that operates the New England grid, can qualify as class I resources. The control area of ISO-New England includes Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. Output claimed as from a class I resource must be verified by ISO-New England or by an independent verification system or person participating in the NEPOOL GIS accounting system. NEPOOL GIS is a generation database and certificate system, operated by the New England power pool, that accounts for the fuel type, emissions, vintage and RPS eligibility of generators producing electricity that is consumed within, imported into, or exported from the ISO-New England control area.

The Massachusetts action is troubling because it was taken mid-stream in implementing the state RPS program, and it will affect projects that are already operating or under construction.

However, the most interesting question is whether this is the start of a broader national trend.

New Rules

The Massachusetts RPS requires utilities to supply at least 7% of their electricity from class I resources in 2012. The requirement increases on an annual basis until 2020 when 15% of retail electricity supplied must come from class I resources.

The new rules for biomass apply to power plants that are not yet in service, but after a transition period, they will apply to operating facilities as well.

To achieve class I status, biomass operators can only use six types of material as fuel. The six are 1) tree tops and portions of trees produced in the normal course of harvesting timber, 2) other woody vegetation that interferes with regeneration and natural growth of forests, such as invasive plant species, 3) fuel derived from forest thinning such as structurally-weak trees or trees removed to reduce the density of timber stands, 4) damaged, dying or dead trees removed due to injury from storms or pests, 5) non-forest-derived residues, such as lumber mill sawdust, non-treated pallets, prunings from park maintenance, or trees removed to convert forest land to agricultural or other permitted uses and 6) wood purposefully grown for fuel.

The rules prohibit the use of fuel derived from construction or demolition activities.

There are further limitations imposed on forest fuel coming from forests with poor soils.

The rules require that the biomass generator demonstrate to the satisfaction of the Department of Energy Resources that per unit of useful energy, the greenhouse gas emissions from the biomass generator, over a 20-year life, will be no greater than 50% of the greenhouse gas emissions of a combined-cycle gas-fired resource employing the most efficient commercially-available technology. The biomass generator must meet this requirement to avoid rejection of its application for class I status.

The regulations impose two "overall efficiency" standards that are expressly intended to raise the energy efficiency bar for energy produced from biomass.

The first standard requires that a power plant using biomass have an "overall efficiency" of at least 50%. Overall efficiency is defined as the total energy production of the facility divided by the energy content of the fuel. Total energy production is the sum of electricity produced, useful thermal energy and the energy value of any products refined on site such as biofuels. Energy produced by the power plant, but used for parasitic load, is not given full credit in the overall efficiency calculation. Further, thermal energy used to dry fuel is not included in the calculation.

To earn any RPS class I renewable energy certificates, the project must achieve an overall efficiency of at least 50%. At 50% efficiency, the project qualifies for only half the renewable energy certificate for each megawatt hour of electricity produced for which other class I resources qualify. It qualifies for full RECs if the overall efficiency is 60% or higher. The REC award is adjusted upward from 50% on a proportional basis if the overall efficiency is between 50% and 60%.

The second standard is slightly more generous for biomass resources that are "advancement of biomass conversion generation units." These are facilities that employ new technology and can demonstrate that the new technology improves the conversion of biomass to energy.

Compliance and Enforcement

The rules impose a variety of compliance requirements on the biomass generator. For example, for each year, the tonnage of eligible fuel used by the generator must be documented in a "biomass unit annual compliance report." The biomass operator must also prepare a report on greenhouse gas production for the year. If the fuel used is forest residue or a result of forest thinning, a biomass fuel certificate has to be prepared along with an eligible forest biomass tonnage report. The biomass fuel certificate has to be certified by the project owner.

The Massachusetts Department of Energy Resources can conduct audits and site visits as "often as the Department determines is necessary to verify compliance . . . ." On a quarterly basis, an independent third-party meter reader, appointed by the department, reports the biomass generator's useful thermal energy, quantity of products refined on site and the other inputs to the overall efficiency calculation.

If a biomass project is out of compliance with the rules on greenhouse gas emissions, then it is placed on probation by the state. If at the end of the five-year probation period, the project has failed to show in any three-year period during its probation that it met the requirements of the rule or that over the five-year period it was in compliance on a net-basis, probationary status is rescinded, and class I status is revoked. Penalties can also result in individual years for noncompliance with the greenhouse gas emission requirements.

Implications

Today, 30% of Massachusetts renewable energy comes from biomass. While for certain biomass projects that are operating and that previously qualified there will be no changes in 2012 (and the exemption from the rules can continue until 2015 if the project is able to demonstrate compliance with the fuel supply requirements of the new rules), the rules will be applied to all currently-operating biomass projects no later than 2016.

The actual impact of the regulations on operating Massachusetts biomass projects is not yet clear. However, application of the rules to existing biomass operators is troubling when one considers the potential changes to both fuel supply and the control of greenhouse gases. With respect to newly-planned biomass projects, the rules have no doubt caused developers to pause. It appears */ continued page 38*

IN OTHER NEWS

casino was essentially a building and had to be depreciated on a straight-line basis over 39 years. The most salient fact was that the US Coast Guard did not recognize it as a ship. The boat had hydraulic mooring claws holding it to land and was attached to land-based utilities through a series of wires, lines, cables and hoses. The Coast Guard said this meant it was "neither used nor practically capable of being used as transportation on water."

The IRS memo is CCA 201225012.

MINOR MEMOS. A US carbon tax of $20 a ton would raise $1.5 trillion over the next 10 years, according to a study released in August by the Massachusetts Institute of Technology. The study assumed the tax would start in 2013 and increase in amount by 4% a year . . . . President Obama issued an executive order on August 30 setting a goal of installing another 40,000 megawatts of cogeneration facilities at industrial sites by 2020. A cogeneration facility is a power plant that produces two usable forms of energy — for example, steam and electricity — from a single fuel. The order directs various federal agencies to work on eliminating barriers to installation of such facilities, including through use of set asides under emissions trading programs, grants and loans and use of "output based approaches" to regulating pollution that recognize the emissions benefits of moving to cogeneration . . . . IRS statistics confirm a trend toward greater use of pass-through entities. The IRS large business and international division has responsibility for the 250,000 largest US taxpayers of whom 75% are now partnerships and other pass-through entities rather than traditional corporations. The IRS is trying to devote more resources to auditing companies with annual revenues of $10 to $250 million. Only 11.9% of such companies are audited currently.

— contributed by Keith Martin and John Marciano in Washington and Clint Steyn in Dubai.

Biomass

continued from page 37

that only combined heat and power projects can meet the new efficiency requirements. This suggests that new biomass projects will be built next to industrial facilities.

Co-location with industrial facilities raises a number of permitting, transmission, fuel transportation and siting issues. Issues also arise in determining the relationship with the thermal energy "host." What happens, for example, if the thermal host needs to shut down for extended maintenance or if the host simply shuts down as a result of a bankruptcy? While these issues are not new (as they have been present in cogeneration for some time), they are critical development issues.

Putting aside the specific changes to the rules for qualifying for class I status, the general notion that rules that have a significant revenue effect on renewables can change mid-stream is troubling. How will lenders react to the mid-stream change in regulation by the state? While financial pro formas can account for retrofits, how will banks and equity investors react to the mere potential for change? In other states in which biomass is operating, or for that matter other forms of renewable or thermal generation, will lenders insist on more restrictive change-of-law provisions? Change of law has already surfaced as a risk allocation issue in states, such as California, that require certification of renewable resources by state agencies.

If the changes imposed in Massachusetts were to be imposed in other states, how would those changes affect a generator's compliance with its power purchase agreement? PPAs often include performance requirements that require the generator to produce a certain quantity of energy over the capacity that is made available under the PPA. If the rules are changed as in Massachusetts, and the rules have operational implications as they do in Massachusetts, will the generator or the utility bear the risk?

Beginning of a Trend?

The Massachusetts rules arise from a debate concerning the overall effect of biomass generation on greenhouse gas emissions (as well as the other environmental impacts of any form of thermal generation). Massachusetts chose to resolve this debate by relying on a 2010 study prepared by the Manomet Center for Conservation Sciences, the "Biomass Sustainability and Carbon Policy Study." Among other things, the study concluded that forest-fueled biomass will generally emit more greenhouse gases than fossil fuels per unit of energy produced.

The study speaks in terms of "carbon debt" (emissions in excess of fossil fuel) and "carbon dividends" (the reductions of greenhouse gas after re-growth of the harvested forest removes the carbon debt). With respect to carbon debt and dividends, the study concluded that "under comparable forest management assumptions, dividends from biomass replacement of coal-fired electric capacity begin at approximately 20 years." It said that "when biomass is assumed to replace natural gas electric capacity, carbon debts are still not paid off after 90 years." It found a significantly shorter payoff period for combined heat and power applications. Ultimately, the Manomet study concluded that policy changes were necessary to avoid a negative effect on forest soils and on sustainability and growth of Massachusetts forests.

> Massachusetts has made it harder for biomass power plants to qualify for full renewable energy credits.

As of now, the study and the resulting regulations appear to be an isolated case. While to some extent the debate concerning the greenhouse gas emissions of biomass continues, there appears to be continued support for biomass in various state RPS rules.

California continues to support biomass generation. While the staff of the California Public Utilities Commission recently opposed a bill before the California legislature that would have authorized some subsidies for biomass fuel collection, the staff comments did not appear to be based on any inherent opposition to biomass. An executive order issued by Governor Arnold

Schwartzenegger, which encourages the use of biomass in energy production, is still being implemented through the activities of a bioenergy interagency working group and an updated bioenergy action plan.

Other states are looking for ways to increase the use of biomass. For example, Oregon has been looking for ways to support the development of biomass as a fuel. The forest biomass working group, which is a multi-disciplinary, broad-based task force assisted by the Oregon Department of Energy, recently issued a draft strategy that supports increased use of biomass in a variety of applications. The strategy, "Growing Oregon's Biomass Industry," was released for comment at the end of July. Similar support is found in the state of Washington.

Like other renewable technologies, biomass projects are having a difficult time moving forward as a result of low natural gas prices and weak electricity demand. However, even with the Massachusetts report and resulting regulations, a number of other states are keeping biomass at least on an even keel with other renewable resources. If the debate concerning biomass has had an impact, it may be in the level of support for large central station power-only biomass power plants, which are having a more difficult time moving past development to construction and eventual operation.

Regardless of your view on greenhouse gas emissions, biomass has the benefit of having a relatively high load factor, while providing a means for disposing of wood and other organic wastes and providing employment. These factors remain particularly important in states with forests that have been struck in recent years by insect or other pathogen invasions. ◎

PPPs: Has The US Finally Found a Path Forward?

Many new public-private partnership transactions are now springing up around the United States to bring private sector dollars to help upgrade roads, airports, public transit, ports, hospitals, courthouses and schools. After several high-profile missteps in the last decade, the US may now have found two workable templates. Project finance lenders seem eager to get involved.

A panel of industry veterans discussed developments at the Chadbourne global energy and finance conference in June. The panelists are former three-term New York Governor George Pataki, Nasir Khan, a managing director with Bank of Tokyo-Mitsubishi UFJ Trust Company, Victor Paulo Saltao, executive director for North America with Brisa Auto-Estadas, Karl Reichelt, executive vice president of Skanska Infrastructure Development, and Cherian George, a managing director of Fitch Ratings. The moderator is Doug Fried with Chadbourne in New York.

MR. FRIED: The projects we will be discussing fall into two categories. There are "greenfield" projects that involve new construction and "brownfield" projects that are privatizations of existing assets. In both cases, the private party also has a responsibility to operate the project for a period of time.

Another way to classify projects is to separate them into availability payment deals and demand risk deals. Availability payment deals are transactions where the government will pay a set sum of money periodically to the private party for keeping the project open or "available" for public use. In a demand risk or traffic risk deal, the private developer is fully exposed to demand or traffic risk.

Some deals that have been done recently in the market include the Midtown Tunnel project in Virginia on which Skanska and Macquarie closed. Virginia also just announced that it is considering 22 more PPP projects.

The international airport in Puerto Rico is under procurement as a brownfield project. The government of Puerto Rico will sell a concession to a private entity to operate and maintain the airport. Ohio State University sold a brownfield concession recently for its parking facilities for about $500 million.

There is procurement underway by the Port Authority of New York and New Jersey for a new Goethals Bridge. The Port Authority put out a procurement to build a new Goethals Bridge between Staten Island and New Jersey and to demolish the existing one. There was a recent procurement for a courthouse in Long Beach. There are many different types of projects currently in the market.

A few months ago, the economic recovery in the United States was gaining momentum. The employment numbers seemed to be going the right way. The stock market was up. Recently, things have not looked so good. Karl Reichelt, what effect does the economy have on this market?

MR. REICHELT: PPPs are a tool that governments can use to create jobs and drive economic develop-

/ continued page 40

PPPs

continued from page 39

ment when times are tough. They are a way to provide needed infrastructure when there it too little money in the budget. A government can leverage its limited public funds three to four times by bringing in a private party. There are roughly $80 billion in infrastructure funds waiting to be invested in this sector.

GOV. PATAKI: PPPs are becoming far more acceptable and far more common. Of course, I said the same thing five years ago. (Laughter.) Five years ago, I was talking about how people were beginning to be more open-minded about having government work cooperatively with the private sector and how governments do not have the money to build new infrastructure on their own. As Karl Reichelt said, there is this enormous need both to create jobs and build infrastructure, so it made sense. But then 2008 happened, which was followed by the federal stimulus of $837 billion for shovel-ready infrastructure. All of a sudden, the idea that the private sector had a critical role to play in this was pushed aside.

I think we have now come full circle and governments have no choice but to pick up again with the private sector. There are three or four good reasons why PPPs will be back in vogue.

First, the federal stimulus is over. Unfortunately, it has not made the slightest dent on the infrastructure needs of this country. We still have trillions of dollars of short-term infrastructure needs in transportation alone, let alone the trillions we need to upgrade the electric grid and so many other items that are in crying need of capital. The federal government is not going to be there. There is no consensus at the federal level that a government that is borrowing $1.3 trillion a year just to keep moving should go into further debt to help states through these projects.

Second, if governments were running out of money in 2006, they are flat broke today. Just look at the projected deficits in California and other states. You are not going to be able to look to the federal government. You are not going to look to the state governments. Traditionally, the state would raise taxes or borrow money. States are no longer in a position to do that for infrastructure, which from a political standpoint is the easiest thing to defer because the bridge will not fall down until the next guy is in office.

Third, there has been a change in the political climate. I worked to do a lot of PPPs when I was governor. We did the air train at John F. Kennedy Airport with Skanska. We privatized the only airport thus far that has been successfully privatized in the country, although Puerto Rico should be happening very soon. The political climate was always very difficult. The results in the gubernatorial recall election recently in Wisconsin are a sign that things are changing. Governors may be emboldened by the results not to defer to public employee union objections to things that are necessary to move a state forward.

The US may finally have found two workable templates for public-private partnerships to build roads and other infrastructure.

When I wanted to do the PPP for the Tapan Zee Bridge, it ran into opposition from the public sector unions. There are private sector unions and public sector unions. It is not surprising to me that Wisconsin Governor Scott Walker got between 33% and 35% of the private sector union vote. Private sector unions want jobs. They want the ability to have their kids follow in their footsteps. A shift in the political climate is limiting the ability of public employee unions to insist that everything has to be done by government, through government or with government.

Finally, Karl Reichelt said there are $80 billion in infrastructure funds looking to invest. We saw massive investment in the mid-last decade in paper assets — mortgage-backed securities and CDOs — and they bombed. The virtue of a road or bridge for a pension fund manager is you can see it. It is a tangible asset. There is growing interest on the capital side in being able to invest in assets one can see.

Brownfield Versus Greenfield

MR. FRIED: Victor Saltao, talking about future projects, do you expect to see more greenfield or brownfield projects?

MR. SALTAO: Both. That said, greenfield projects are more likely to go through politically. They also take more time, since they require new permits, environmental studies and the like. They fill a need. Managed lanes on existing roads are also becoming more popular. They will have congestion pricing. The lanes add 20% to 40% more capacity to an existing highway. Some 15 to 20 states are considering managed lane projects currently. They are faster to implement and find greater public support since they give drivers the option of arriving downtown faster by paying a toll during rush hour.

MR. FRIED: The amount of the toll varies depending upon the level of traffic. If there is heavy traffic in the managed lane, then the toll will be higher to discourage people from using the toll lane. If traffic is light, then the toll will be less to encourage people. Cherian George, do you expect to see more availability payment deals or more demand risk deals in the future?

MR. GEORGE: Most state departments of transportation are looking at demand risk projects. Demand risk projects, particularly of the greenfield variety, are challenging to finance. There are lots of risks, and lenders have been taking hits on many occasions with these projects. This means that they need some public money to make them more viable. For that reason, I think the market will move eventually to availability payment projects. If the government is going to have to spend money in either case, it may do better to take back some of the risk.

MR. FRIED: Nasir Khan, given the departure of various European lenders from the US project finance market, who do you expect to fill the void? Do you think that Canadian and US banks might get more involved? Where will the money come from to finance these deals?

MR. KHAN: The European banks have not fully departed. You may see tenors shorten. You may see slightly higher pricing. Perhaps the appetite is a little bit lower, but the European banks are still very much there.

As a Japanese bank, we are very happy to fill some of the gap, but frankly, we are also glad to see the European banks still active because we need them to have a healthy market. They have been sophisticated project finance lenders for a very long time.

When you look at a PPP bank deal with revenue risk, the market is probably capped at a little over $500 million. The Ohio State University parking deal and San Juan Airport project are both within that range.

The Midtown Tunnel deal ended up having a very strong execution in the private activity bond market. The banks looked at it, but being north of $600 million would have made it challenging from a capacity perspective. Some national US banks, like Wells Fargo, have come into the market. Other US regional banks are also starting to show an interest.

The fact that Cheniere is able to finance close to a $4 billion LNG export terminal with bank debt is encouraging. The lender capacity to handle large deals is much greater when there is the potential for cross sales and follow-on business.

There is a very strong private activity bond market in the US. It is a tax-exempt bond market. In addition, you have TIFIA funding as another source of capital. The bottom line is that this sector can tap multiple deep pools of capital.

MR. FRIED: TIFIA is basically a special form of lending from the US government at very low rates with long tenors.

Governor Pataki, I hope you don't mind, but I want you to talk about politics for a minute. (Laughter.) We were talking about brownfield versus greenfield projects. The Chicago Skyway privatization was a brownfield project that got a lot of interest. Everybody expected an avalanche of deals to follow, but politics intervened. Do you think brownfield procurement is more politically charged than greenfield procurement?

GOV. PATAKI: Yes, and the Chicago Skyway and the Indiana Turnpike are perfect examples of what can go wrong. Governor Daniel ran into enormous public opposition when he tried to privatize the turnpike. A hundred years ago, the country bumpkin would come to New York City, sit under the Brooklyn Bridge and look in amazement, and the city slicker would say, "You like that bridge? I'll sell it to you." And the bumpkin would buy it. Now the city slicker goes out to the country and says, "I see that bridge you have. Will you sell it to me?" (Laughter.)

It is a harder sell to take an existing asset that people use every day and say that it will no longer be your neighbor plowing the snow or filling holes and the government running it, but it will be some foreign entity. Brownfield sales elicit a more emotional reaction than greenfield projects do.

I remember sitting down with Governor Corzine when he was governor of New Jersey. He was going to privatize the New Jersey Turnpike. He sat down and said, "I have this great plan. We are going to bring the private sector into the New Jersey Turnpike." I said, "What are you going to do with the money?" He said, "Well, we're going to pay down debt, and we are going to do this and that." And I said, "You will never get it through." He asked, "What do you mean?" */ continued page 42*

PPPs

continued from page 41

I said, "You are taking an existing public asset that people are used to using, privatizing it, and they will not see anything tangible in return."

The difference with a greenfield project is that you can tell the public it will have a new road or new bridge soon that is impossible to build without help from the private sector. There is less of an emotional reaction. Greenfield projects are an easier sell politically because people see something tangible in return.

Politics by Asset Class

MR. FRIED: Karl Reichelt, do the politics vary by asset class — for example, a road, parking facility or courthouse?

MR. REICHELT: To do a public-private partnership effectively, you have to have strong political will. That means that the governor has to be willing to put his or her credibility on the line to work that project. The math must make sense. Strong political support is a must because there is always opposition in this market to bringing in a private partner to make improvements.

Take the Midtown Tunnel project. It is a $2 billion project. The financing is $695 million in tax-exempt private activity bonds, $422 million in a low-interest federal loan, $300 million from the state and $320 million in cash from the private sector. The way I look at it Governor McDonnell took $300 million of state money and leveraged it into a $2 billion dollar project that was both nationally and locally significant. The project had been in the works for 20 years, and it will be now built in five years taking advantage of 2012 prices. It took a strong will on his part to push it through under huge political opposition at a time when he was hoping to be considered as a vice presidential candidate.

We need a new mindset where governments focus on delivering services to taxpayers rather than owning bricks and mortar. Companies like ours are really good at doing the building, financing, operation and maintenance for extended periods and being held accountable through performance-based contracts.

When I was in government, we tried to do huge projects and always struggled with delivering them on time and on budget. The experience with public-private partnerships is that 85% of projects are done on time, on budget with high efficiency and typically with good results for the government. The inverse is true of state or federal projects: 85% are over budget, over time and obsolete by the time they are completed.

GOV. PATAKI: Our audience tends to think rationally. Politics are a combination of the rational and the emotional. Karl mentioned asset classes. People do not tend to identify closely with a road. But schools and hospitals are another story. I was amazed when I first went up to Ontario, Canada and saw that they were doing everything privately, including schools. It is like pulling teeth even to get transportation projects done here. So as you look at those asset classes, the garage is easy. No one lies awake at night saying, "What a wonderful garage we have here in Albany, New York."

MR. FRIED: It depends upon the type of car you have.

GOV. PATAKI: It depends on your car. My cars don't even make it into the garage. (Laughter.) But when you're talking about your neighborhood school, it is a different story. It is a mistake when dealing with the public to lose sight of the emotional part of the equation.

MR. FRIED: We have been making progress on the transportation front. What else is holding back the social infrastructure?

MR. GEORGE: There has been a lot of bad press associated with PPPs. This is, in large part, because there has been no big picture thinking about public policy on how this should work and why it can provide better service to the public over time. What we have seen instead is a gradual shift, state by state, of people making individual decisions that lead to one project here and another project there.

We at Fitch monitor about 175 public authority ratings in the transportation sector. We also monitor privately managed project finance ratings. The one thing that you have in the private sector is clear contracts that say you will do "X" and meet "X" and "Y" standard and, if you do not, you will not be paid. The very people who are imposing those requirements on the private sector do not hold themselves to those standards. There is an opportunity to have disclosure on public performance to hold both parties accountable so that the level of service on every asset improves.

MR. SALTAO: When you try to compare turnpike numbers with roads, bridges, whatever, you are comparing apples and oranges. It is difficult. There are professors and commissions trying to make such comparisons. The only way to sell a road project is to inform the public about the benefits and what it costs to have a turnpike at an acceptable service level.

GOV. PATAKI: Another difference between public infrastructure and PPPs is you have a contractual relationship. If one side does not perform, you sue and get justice. However, when a project goes wrong, the government may have legal rights, but it does not matter if you are in public office and the people say, "What in God's name have you done here? The road is half done." Just to be able to say that we can hold private parties legally accountable does not cover the risk to the governor. Success breeds success, and failure breeds contempt. Legally you can collect, but in the meantime it is an enormous public embarrassment. That difference makes politicians very cautious before going into this type of arrangement.

Federal Support

MR. FRIED: Educating government officials and the public about the benefits of PPPs takes time. We have made considerable headway, but a lot remains to be done. Nasir Khan, what further action do you expect at the federal level to encourage PPPs?

MR. KHAN: On the federal level, there are two major topics of discussion. One is reauthorization of the transportation bill. It is expected to include more TIFIA. The other big topic of discussion, which seems to have lost momentum, is creation of a federal infrastructure bank.

At the state level, we are seeing a lot more acceptance. There are more than 30 states with some form of PPP legislation. The states and municipalities have little choice. They have relatively limited access to funding at a time when the private sector has deep pools of capital to invest. A project like the Midtown Tunnel is an excellent example of where a state was able to leverage its funds into a much larger investment. Virginia has been very good at doing that.

MR. FRIED: How do you see the 2012 Presidential race affecting PPPs?

GOV. PATAKI: I think Governor Romney would be far more inclined than the current administration to be open to private sector involvement in what traditionally has been a government activity. Virginia Governor Bob McDonnell is leading the way and, before that, Texas Governor Rick Perry was leading the way. These are states that have conservatives in charge who believe in limited government, but that is not always the case. The Daleys in Chicago have been very aggressive on this. Pennsylvania Governor Ed Rendell was very aggressive about involving the private sector.

MR. FRIED: How do you think a Romney administration would feel about increasing TIFIA funding?

GOV. PATAKI: I would like to think that it could be done with bipartisan support. These things really do make sense, and infrastructure is something that can cross the political spectrum. It only got started under Abraham Lincoln. It is not as if this is a new development. Unfortunately, there are some people in my party who believe the federal government has no role. TIFIA should be viewed as a catalyst to mobilize the private sector.

It is harder to persuade the public to bring in a private party to own an existing asset than to build a new one.

When I was governor of New York, one of the interesting things I saw was that it was not as much a partisan issue as it was geographic. It was big state versus small state. It did not matter if you were Republican or Democrat. If you were from a relatively urbanized state, you supported mass transit funding from the federal government. If you were from a rural state, you wanted more for highways and less for mass transit.

MR. FRIED: Victor Saltao, we have seen a socialist president elected recently in France who does not support wider use of PPPs. Will this create more interest in the US market?

MR. SALTAO: We have worked over the last 10 to 15 years on PPP projects with various socialist governments in Europe, like Spain, Portugal, Italy and Greece. We are paying now, and we will pay in the future, for the socialist policies on transportation. There were a lot of availability projects that did not make economic sense and that became very expensive later. They were good politically when they were completed, but the traffic volumes were much less than forecasted, making the projects burdensome to carry. Those are the lessons.

My company is operating roads in India, and it has been active in Latin America, Europe and the US. We expect to remain active in the US market. The opportunity is here.

/ continued page 44

PPPs

continued from page 43

Outlook

MR. FRIED: We are coming to the end of our session. I would like each of you to tell me your view of the current market.

MR. REICHELT: We are very optimistic. Five to seven PPP projects will close in 2012. That is a high volume for this market. In the past, the pace was two to three projects a year. By comparison in Chile, the number is eight to 10 projects a year. We are seeing that projects in the US can still get done in a tough political and economic environment. This is really good for the market. The Midtown Tunnel project in Virginia was four times oversubscribed. Investors are interested. Governors are catching on.

The uncertainty at the federal level is having an effect. We are in the same boat as the renewable energy developers. I do not think the politicians in Washington understand what uncertainty does to the market. The Senate and White House coordinated on wanting to create jobs and build infrastructure, but they are killing PPPs, which are a great way to create these jobs and infrastructure.

All of that said, I am optimistic about the US market. We are currently tendering three big multi-billion dollar projects.

MR. KHAN: For a long time, we have been a transaction-constrained market, not a capital-constrained market. What we have seen in the first half of 2012 is very encouraging. The Midtown Tunnel and Presidio projects have already closed, and the Ohio State University parking and San Juan Airport projects are expected to close very soon. This compares to last year when you had just one project close, the PR-22 toll road deal. So already we have seen four times what was accomplished last year, which is encouraging.

MR. SALTAO: The authorities need to look over the current pipeline and prioritize projects. They should push forward with the ones that are truly ready. The capital is ready to be deployed.

MR. GEORGE: No pun intended, but the rubber meets the road on TIFIA. It provides around 33% subordinated debt and really enhances the credit quality of these projects. There is talk of increasing the funding, which would be an exciting development. However, the process for tapping into TIFIA is highly politicized. The program lacks the right level of staffing and, at every step of the way, the Office of Management and Budget and the Treasury have to agree on everything. The program does not follow any kind of market precedents. This makes it difficult and expensive to execute deals. The organization and structure of TIFIA have to change to make the program more useful. I have one cautionary thought on funding, though: my concern with a large funding increase is that unless the staff is geared up to deal with a larger volume of projects, the government will end up funding projects that should not be funded and that will bring a full halt to the program when a big blowup takes place.

GOV. PATAKI: I am more than optimistic about the future for infrastructure and PPP projects domestically. Politicians like to think that they are leaders, but they are really herd players. For the longest time, nothing was happening. As Nasir Khan said, last year there was only one project. This year, there have already been four. As more successes happen, states and municipalities will find more courage, as will their elected officials. The capital is there. The need is there. The public lack of capability is there, and the political climate is becoming more receptive. I am extraordinarily optimistic about the next five years. I think this is the place to be. ◎

Distributed Solar: Unalloyed Growth Story?

Solar companies broke open the US rooftop market by offering customers the option to lease or buy electricity from solar systems that the companies put on roofs but continue to own. Customers like the model because they do not have to pay the full cost of systems up front. Will the model catch fire in other countries? What are projected growth rates in the US distributed solar market? Are the developers making money? Is there much potential beyond the handful of existing states in which developers are already operating?

Three CEOs of distributed solar companies and two tax equity investors talked about the rooftop solar market at the Chadbourne global energy and finance conference in June. The panelists are Danny Kennedy, founder and director of Sungevity, Lyndon Rive, CEO of SolarCity, Vikas Desai, CEO of EchoFirst, Richard Moore, division head for strategy at Washington Gas, and Edward Levin, director of renewable energy with Rabobank. The moderator is Todd Alexander with Chadbourne in New York.

MR. ALEXANDER: The mood at this conference is one of mild pessimism about the renewable energy sector in the United States, particularly for wind. However, I do not think we will hear the same pessimism from the distributed solar people. The US solar market grew at an 85% rate year over year to the end of the first quarter this year. Panel prices are continuing to fall. Panels now cost less than $1 per watt before installation. The United States is now the fourth largest market in the world for photovoltaic solar behind Germany, Italy and China. Many people believe the opportunities in wind and other renewables are becoming more limited. Tax equity investors are becoming more comfortable with residential solar installations as an asset class. Tax equity investors used to be able to charge a premium to distributed solar companies. We will talk about whether that is still the case and where people think rates are headed. We will also talk about some small headwinds in the market: for example, tariffs that the US just slapped on Chinese solar cells. We will also touch upon the plummeting SREC — or solar renewable energy credit — prices in the northeast.

Lyndon Rive, your company has been on a rapid trajectory. What do you foresee for the distributed solar market in the next 12 to 24 months?

MR. RIVE: Rather than focus on SolarCity, let me talk about what I think the industry as a whole can achieve. The industry has had two years of rapid growth. Customer demand remains strong and should be enough to sustain that growth for the next few years.

The declining cost of technology combined with the rising cost of retail electricity is opening rooftops for solar in more and more states. The different solar leasing companies are all offering roughly the same value proposition. We typically price around 10% to 15% below your retail rate so when you have a scenario where a consumer has a choice of paying 10% to 15% more for dirty power or 10% to 15% less for clean power, what do you want to do? People prefer to pay less and do something good for the environment at the same time.

MR. ALEXANDER: Danny Kennedy, one appealing thing about the distributed solar market is you are competing against retail electricity prices, unlike utility-scale solar developers who compete in a wholesale market. What do you foresee for the distributed solar market in the next 12 to 24 months? Does rooftop solar make more sense than utility-scale solar?

MR. KENNEDY: Like Lyndon, we are very bullish. We expect nearly to double our customer base this year and to double again next year. We are presenting customers with a lower cost way of getting solar electricity. As to your question about residential versus utility-scale, obviously we will be the first place where solar electricity reaches grid parity because we are competing against a retail rate for electricity. There are many potential markets around the world. There is a natural market for solar because solar is becoming the lowest cost provider of electricity.

MR. ALEXANDER: How much does the typical homeowner save on his electricity bills by installing rooftop solar?

MR. KENNEDY: The savings vary by utility service territory. The pricing formula Lyndon described for the solar leasing industry is right. We are all trying to offer customers 10% to 15% savings, at least over the lifetime of the lease.

MR. ALEXANDER: Vikas Desai, your company has a different approach. Tell us what it is.

MR. DESAI: EchoFirst is a product company. We combine rooftop solar panels for generating electricity with a solar hot water heater. We have remote metering and monitoring of the system. We have more than 50 patents all around integrating base technologies that have existed for years and in many cases for decades. We are positive and energized about where solar is going. There has been a lot of recent innovation. Companies like SolarCity are leading on financing strategies. An army of installers has come into the game. States like California now have more than 2,000 installers that install solar. You also see a lot of signs of the market maturing so that at every kitchen table there are on average three to five bids.

MR. ALEXANDER: What kind of value proposition are you offering? How much cheaper is it buying electricity and hot water from you than from the local utility?

MR. DESAI: Our value proposition is similar to what the other companies are offering. Our customers typically end up saving 10% to 15% off their utility bills.

MR. ALEXANDER: Rick Moore, how does distributed solar compare to the other opportunities you have as an investor?

MR. MOORE: We think about distributed generation as less of a technology play and more of something that is central to the goals of our company. We want to be a company that is focused on generating clean and efficient energy. This is part of our DNA. We see distributed solar as a tremendous opportunity. We have an investment in American Solar Direct, which is a residential rooftop company in */ continued page 46*

Distributed Solar

continued from page 45

southern California, and we are also doing commercial solar thermal nationwide with Skyline Innovations, a company based in Washington, DC.

The reason why distributed generation is so interesting is the value proposition to the customer. We think customers are looking for protection against fluctuating energy prices. They are looking to be green. They are looking to lower their energy costs. They are looking for reliability. Distributed solar offers all of these things. We like this market because it is a market where customers have reasons to seek out solar companies and the products they offer.

MR. LEVIN: Anybody in the prediction business is asking for trouble. All I can say is the industry will have to adapt to a new environment in six months. It seems clear that the Treasury cash grant is, unfortunately, a thing of the past. Frankly we have been living on the grant for the last two years. The industry is in a better position than wind because the investment credit for solar runs through 2016. It is not good for solar to see the wind industry suffer the way it is suffering now. Anybody who has been to the global windpower conventions the last few years has seen attendance shrink significantly from year to year. That is not good for solar.

MR. ALEXANDER: Lyndon Rive, SolarCity has been a market leader in raising capital for rooftop solar. You have pioneered various forms of master financing facilities to try to lower transaction costs. How are you finding financing sources and particularly tax equity as Treasury cash grants recede as a source of capital?

MR. RIVE: Since our initial transaction with Ed, we have closed on another 22 master tax equity facilities. The potential pool of investors has been expanding. What is particularly exciting is we are starting to see corporations show an interest; tax equity is no longer being supplied solely by banks. There is a learning curve for new entrants. The financing structures can seem complicated. However, once investors get up the learning curve, they almost always make repeat investments. The return for the risk profile is pretty good.

MR. ALEXANDER: What kind of returns are we talking about?

MR. RIVE: The returns can range from 6.5% at the low end for debt to 10% to 12% at the upper end for tax equity. We are trying to reduce our overall cost of capital by combining back-levered debt with tax equity.

MR. ALEXANDER: Do you think we will see a decline in tax equity yields given the success of the solar industry, growing familiarity with the asset class and a low customer default rate?

MR. RIVE: Tax equity yields are not a reflection of the risk profile of the asset class; they are function of supply and demand for tax equity. As long as there is more demand than supply, the rates will remain high. As the supply of tax equity increases, the cost of tax equity will fall. The maturing of the

The US solar market as a whole is on a path to grow 71% in 2012 with slower growth forecast in 2013, but the rooftop solar market is booming.

Cost of Capital

MR. ALEXANDER: Ed Levin, transaction costs have to be an issue when trying to finance lots of small solar systems. Don't they push up the cost of capital to these companies?

MR. LEVIN: There is no doubt it was a problem five years ago, and it remains an issue in this market. The only way I have seen the model work is for solar rooftop companies to batch together large numbers of systems and to have standard contracts with customers.

MR. ALEXANDER: Are there many tax equity investors interested in financing solar residential installations?

MR. LEVIN: More and more tax equity investors are showing an interest in the sector. It was not an easy sell with credit people and management when I did my first financing for SolarCity five years ago. The sector now has the scale to attract people who are interested in making large tax equity investments or loans.

MR. ALEXANDER: Where are tax equity rates today? Are they going down? Will the drying up of the wind market bring rates down further? Are investors getting more comfortable with the asset class?

asset class will not lead necessarily to lower tax equity rates. However, it does get reflected in lower debt rates. Debt rates are a better reflection of the market's view of asset risk.

MR. ALEXANDER: Danny Kennedy, how has Sungevity overcome the challenges of trying to finance small projects? Where do you see the tax equity market headed?

MR. KENNEDY: It has been an ongoing and interesting challenge, but things are improving. As Lyndon said, tax equity yields are more about supply and demand than the riskiness of the asset class. I am optimistic that things will improve in the US as more corporations start making tax equity investments. Rooftop PV is becoming more financeable around the world. We just started a joint venture in Australia where we see a lot of interest from lenders. Retail electricity prices are high in Australia, providing an entrée for residential solar companies.

MR. ALEXANDER: Rick Moore, you just heard what they said about tax equity investors. Do you feel appreciated? (Laughter.)

MR. MOORE: I was hoping to hear from the panel that tax equity yields would go through the roof in the next six months, so I am disappointed. (Laughter.) We are one of the "corporations" to which Lyndon and Danny were referring. We are continuing to see very interesting opportunities come our way, and we remain active. We have been investing in this sector for two years and have built some capabilities that foster our ability to remain active. I think the challenges associated with developing these capabilities remain barriers to new entrants in the market. For example, the complex accounting approaches and various investment structures require time and effort to understand. There are competing technologies that require constant assessment and a large number of developers with differing capabilities. Washington Gas is now trying to look at ways to leverage the capabilities that we have developed, perhaps by aggregating capital with some other peer tax equity investors. That is one way to increase the supply of tax equity.

Grid Parity

MR. ALEXANDER: When will this sector reach grid parity? How close is it to competing with other sources of electricity?

MR. RIVE: The answer varies by state. We are installing systems in dozens of communities in places like Nevada, Florida and Utah — nontraditional solar markets. We have to push the boundaries.

MR. ALEXANDER: Will we still be talking about tax equity in 2016?

MR. RIVE: Yes. The investment tax credit for solar drops from 30% to 10% after 2016, so there will remain a need to barter tax subsidies for capital in the tax equity market. However, securitization structures will become more critical after 2016 as solar companies package portfolios of solar residential leases, have them rated, and then borrow against the future rents. The key to continued cost reduction is volume. As the incentives decrease, the margins are getting tighter because the incentives are decreasing faster than the cost of technology is decreasing. The only way you can profit is by pushing more volume through your fixed sales infrastructure.

MR. ALEXANDER: Does this mean that rooftop solar might only have a long-term future in the southwestern United States?

MR. RIVE: Without any incentives, you would have to sell electricity for 17¢ or 18¢ a kilowatt hour. US Energy Information Administration forecasts for 2017 suggest that these numbers would work for about 20% of the US population.

MR. ALEXANDER: Rick Moore, what's the future for this sector? Do you foresee a wave of consolidation?

MR. MOORE: We are indifferent as investors as to whether there are many companies or a few companies. As a 160-plus-year owner and operator of energy assets, for us, the ability to own a working asset is more important than how that asset arrived on our books. It does not matter if the assets come from a single supplier or 20 suppliers. We see a future under either scenario.

MR. ALEXANDER: Vikas Desai, do the solar rooftop companies need to consolidate to reach the type of volume to which Lyndon Rive referred?

MR. DESAI: We are a long way from a mature sector. A lot of the action is happening upstream where there is severe overcapacity among manufacturers of solar panels. Compared to more mature industries like HVAC or windows or other home improvement categories, solar is at mile marker one. I think we are far from consolidation. Many new business models will still emerge.

Opportunities Outside the US

MR. ALEXANDER: Danny Kennedy, what opportunities are there for investors, panel suppliers and developers in markets outside the US? Will the same lease model that has led to a boom in solar rooftop installations in the US take hold in other countries?

MR. KENNEDY: There is a lot of opportunity. There is opportunity wherever the price of electricity for residential customers is high. This includes Australia / continued page 48

Distributed Solar

continued from page 47

where my family pays 22¢ a kilowatt hour in the suburbs of Sydney for electricity, and the price is expected to go up 16¢ on July 1 and another 16¢ again next year. Brazil is one of the fastest growing economies in the world. Brazilians are paying 23¢ a kilowatt hour for residential electricity.

MR. ALEXANDER: Vikas Desai, do you have your hands full in the United States? Are you looking overseas as well?

MR. DESAI: We are looking overseas. There are many, many exciting markets. There are several potential markets in Europe. We are also looking at places like Japan, Australia and Latin America, though we do not intend to go there in the immediate future. Markets like Turkey will become very interesting. There is a focus on certain markets in the Middle East as well.

MR. ALEXANDER: Lyndon Rive, what about SolarCity?

MR. RIVE: The market is insanely huge and sometimes the biggest challenge is to remain focused on what we are doing here because it is exciting to move into new markets. However, I have to finish this job before I can do that job. The market expansion is essentially going to be infinite in our lifetimes with distributed solar. Countries are starting to realize the benefit of this. For now, we are focused solely on the US. ◎

LNG Exporters Queue Up

by Donna J. Bobbish, in Washington

The US Department of Energy gave final approval in August to Sabine Pass Liquefaction LLC to export up to the equivalent of 2.2 billion cubic feet of liquefied natural gas a day for the next 20 years to any countries with which the United States does not have a free trade agreement requiring "national treatment" for trade in natural gas.

"National treatment" for trade means treating an imported good the same as a locally-produced good once it enters a market.

The Sabine Pass Liquefaction approval is the first such approval to be granted.

The agency has another six applications pending for authority to export more than 1 billion cubic feet of LNG each per day, plus three more applications for authority to export smaller quantities of LNG. Earlier this year, a senior US Department of Energy official indicated that action on these nine applications will await completion of a two-part study that the agency commissioned to examine the effects of large-scale exports of domestically-produced LNG on domestic gas supplies and prices. Part one of the study was released in January.

Shift to Exports

Although Alaskan LNG has been exported to Japan for more than 30 years, the lower 48 US states began importing LNG in the 1980s, based on projections of decreasing US natural gas supplies. However, the US Energy Information Administration, or EIA, reports that US LNG imports decreased in 2011 to 349 bcf, the lowest level since 2002.

Advances in natural gas drilling techniques, principally hydraulic fracturing or "fracking" that allows production of natural gas from shale, have led to dramatic increases in US natural gas production. Gas production is increasing faster than US demand for natural gas, causing natural gas prices to decrease. EIA reported in July that while US natural gas spot prices fell over the past two years, LNG prices in international markets rose significantly during the same period.

Because natural gas prices are higher outside of the US, developers are looking at projects to export domestically-produced LNG, focusing mainly on modifying existing LNG import terminals to also allow LNG exports rather than building entirely new terminals.

Legal Approvals Required

Exports of natural gas, including LNG, from the US require prior authorization under section 3 of the Natural Gas Act, and jurisdiction over LNG export projects is divided between the Federal Energy Regulatory Commission and the US Department of Energy.

FERC authorizes the construction and operation of LNG export facilities upon a finding that the construction and operation of such facilities are not inconsistent with the public interest. In April, FERC authorized construction of liquefaction and export facilities at the existing Sabine Pass export terminal in Cameron Parish, Louisiana.

The Department of Energy grants authority to export. Exports of LNG to countries with which the US has free trade agreements requiring national treatment for trade in natural gas are considered automatically consistent with the public interest under the Natural Gas Act and must be approved without modification or delay. The US had such free trade agreements with 17 countries as of mid-May: Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Republic of Korea and Singapore.

Authorization to export LNG to countries without such free trade agreements, on the other hand, requires DOE to find that the proposed exports are not inconsistent with the public interest.

This requires decisions on, among other issues, whether the gas is needed domestically, whether the proposed exports pose a threat to the security of domestic natural gas supplies and whether the proposed exports are consistent with the US policy of promoting competition in energy supplies by allowing commercial parties to freely negotiate their own trade arrangements.

Sabine Pass Liquefaction received conditional authority in May to export LNG to countries without free trade agreements with the US, subject to further environmental review. DOE said that Sabine Pass Liquefaction submitted studies indicating that the US is expected to have more than enough natural gas both to export the volumes proposed and supply domestic demand for the 20-year term of the export authorization. It said no one intervened in the proceeding to suggest otherwise.

DOE has approved one application to export LNG. It has another nine applications pending.

According to DOE, the studies submitted by Sabine Pass Liquefaction indicated that there will be only a modest increase in the domestic market price for natural gas through 2035. DOE suggested this price increase will result from increasing marginal costs to produce gas for LNG export rather than from a convergence of domestic natural gas prices with prices in international markets where the price of natural gas is linked to the price of oil.

However, the agency took administrative notice that future government actions as well as advances in technology could affect the supply and price forecasts. In particular, DOE said that federal agencies are still looking into the environmental and safety consequences of shale gas production, and the results of this review could reduce future US natural gas supplies. DOE also postulated that fracking could be more widely adopted outside the US, leading to an increase in international gas supplies and reducing prices for gas abroad. Finally, DOE indicated that US natural gas demand could increase over time.

Future Monitoring

DOE said it would monitor the situation, because "[t]he cumulative impact of these export authorizations [for Sabine Pass Liquefaction and any other exports the government approves in the future] could pose a threat to the public interest . . . . In the event of any unforeseen developments of such significant consequence as to put the public interest at risk, [DOE] is fully authorized to take action as necessary to protect the public interest." The agency did not say what actions might be taken.

However, subsequent statements by senior DOE officials suggest that the most likely action, if the agency starts to fear that domestic natural gas supplies are endangered, is to deny or limit additional LNG export authorizations rather than rescind existing export authority. Energy Secretary Steven Chu told the *Cleveland Plain Dealer* in January, "You don't permit a whole rash of [exports] and then find out what a terrible mistake you made."

In February, Christopher A. Smith, a deputy assistant secretary at DOE, told Rep. Edward Markey (D-Massachusetts) in a letter that the government does not intend to use its authority to modify previously-granted export authorizations as a price maintenance mechanism in the event of a price spike in domestic prices of natural gas. Smith acknowledged that the good-faith expectations of private investors in export terminals will make it hard to withdraw or modify export licenses "except in the event of extraordinary circumstances."

Smith also told Markey that DOE will not address the pending applications for export of LNG to countries with which the US does not have free trade agreements requiring national treatment for trade in natural gas until DOE has received and reviewed the results of two studies it commissioned in August 2011.

EIA released the first part of the study, an assessment of how specific scenarios of increased */ continued page 50*

LNG Exports

continued from page 49

natural gas exports could affect US energy consumption, production and prices, in January. The second part of the study, which is being done by a private contractor, has not been completed yet. It will address the impact of the same specific scenarios of increased exports examined by EIA on the US economy and manufacturing sector.

Now that Sabine Pass Liquefaction has been given authority to export, the question is what DOE will do about the other pending applications once the DOE study is completed. The DOE deputy assistant secretary told Congressman Markey in February that "no decision has been made whether to approve, limit, phase-in or deny the presently pending or any future proposed export authorizations." Some of the options DOE could consider include approving all of the pending applications on the assumption that not all of the projects that receive authorization will be constructed, or approving the applications but only authorize exports up to a certain level.

In the meantime, DOE is being lobbied by members of Congress from gas-producing states to allow more LNG exports. On August 7, the same day that DOE granted final authorization to Sabine Pass Liquefaction, 44 members of the House of Representatives from Texas, Louisiana, Oklahoma and Arkansas wrote to Energy Secretary Chu arguing that surplus US gas supplies need an international outlet and urging DOE to "take the steps necessary to expedite the approval process for the export of LNG." ◎

The Remaking of the US Power Sector

Low natural gas prices are turning the energy sector upside down. Gas prices are at their lowest level since 2002, having fallen 54% in the past 12 months. The low prices have stopped construction of new gas storage facilities, led to interest in LNG export terminals and made existing gas-fired power plants more valuable. Traders have been betting for more than a year on the price to rise. Forward price curves continue to show a steep increase during a period when the ratio of gas to oil prices has gone in the last year from 26 to more than 50, against a 15-year average of 11. Will the costly new export terminals be finished in time to earn a return? Will most of the new gas-fired power plants built end up in rate base? Are low gas prices a source of opportunity as well as peril for the renewable energy industry?

A group discussed these and other questions at the Chadbourne global finance and energy conference in June. The panelists are Christopher Smith, a managing director of Energy Management, Inc., Paul Cavicchi, executive vice president of IPR-GDF SUEZ Energy, Roberto Simone, managing director and head of project finance at Société Genérale, and Noam Ayali, a project finance partner with Chadbourne in Washington. The moderator is Ben Koenigsberg from the Chadbourne New York office.

MR. KOENIGSBERG: Production of natural gas in the US grew nearly 8% in 2011, principally because of shale gas resources. Estimates of recoverable shale gas are between 700 and 1,800 trillion cubic feet. US shale gas production increased fivefold between 2006 and 2010, and the Energy Information Administration estimates shale gas will ultimately reach 13 trillion cubic feet by 2035. The questions are what are we going to do with all this natural gas and how will the renewable energy industry will react? Chris Smith, gas prices are currently at about $2 an mcf. Do you expect them to increase or stay put?

Natural Gas Price Outlook

MR. SMITH: They will increase. The thing to remember is that $2 an mcf is the spot price. The forward price curve matters as much or more than the spot price. Even within a year, gas prices vary considerably.

Gas prices will increase for two reasons. One is that the current price of gas on the spot market appears to be below the average total cost. The average total cost is the marginal cost to produce plus a return on capital. It doesn't look like gas producers are recovering their costs, let alone earning a return, at current prices.

The other reason is demand will increase. We had a very warm winter with the result that producers stored a lot of gas. You are now seeing a runoff of that gas, which is helping to keep prices low. This is a temporary phenomenon.

MR. KOENIGSBERG: Demand may also increase relative to supply if we start to export gas to other countries. A lot of gas import facilities are sitting idle currently. These facilities are now being made bi-directional. However, the politics of gas exports mean that only one company is authorized currently to export. Should the US allow more gas exports?

MR. SIMON: In the spirit of full disclosure, we are advising Cheniere, the export terminal to which you referred. The simple answer is absolutely: the government should permit companies to export natural gas, but I think the broader question is: does it really make sense, from the standpoint of US energy policy, to export our natural gas? We have an abundant resource. If you look at the forecasts, even in fairly high demand growth scenarios, natural gas prices are not forecast to rise dramatically over the next eight to 10 years.

Exports are a source of revenue. It is in the US national security interest to be part of an integrated energy market and to have other countries look to us as a source of energy.

LNG exports could eventually increase demand for US natural gas by as much as 15%.

Finally, remember that it was not so long ago that people were talking about natural gas imports and building something like 33 LNG import terminals. People forget how difficult it is to find enough credit worthy parties to sign terminal use agreements under which they are obligated to make capacity payments. The critical element in building an LNG export terminal is finding someone of sufficient size, credit quality, capability and desire to take natural gas in the United States and market it to the rest of the world. There are not many companies who are capable of doing that or have an interest in doing it. It is this, rather than politics, that will limit the number of export terminals.

MR. CAVICCHI: Exports are likely to have a marginal effect on gas prices in the United States given the quantity of shale gas being produced.

MR. SMITH: The Energy Information Administration is predicting that we will have 16 bcf a day of export capacity within the next five to 10 years. Let's assume that all the planned export terminals are built. The EIA also estimates that we will average about 10 bcf a day of actual exports. The United States uses around 65 bcf a day now, and this is in a very depressed environment. Natural gas consumption is linked to industrial demand. We are in a very soft economy.

If we start exporting 10 bcf a day, that is equivalent to a 15% increase in demand. That is a significant swing. A lot of industrials look at this potential increase in demand and see themselves being compromised economically.

This underscores the need for diversification. I used to work at Enron. I was a young associate and was sitting around the table at lunch with gas industry veterans like Stan Horton, who was instrumental in developing Cheniere, and they would talk about what they wanted to do in life after Enron because things were not looking so good at the time, and they were saying "LNG is where it is; we need to have import terminals because we are going to run out of gas in 10 years." This was 2003. Here we are now. The import terminals are idle, and the talk is about exporting gas and turning the terminals around. It underscores how volatile this market can be and how things can play out differently than what you expect. I have never seen a long-term forecast that is correct. That is why you have to be diversified.

MR. KOENIGSBERG: If you don't believe forecasts, then what do you make of the EIA forecasts?

MR. SMITH: The EIA report was controversial. Some people said the elasticity of supply is much greater than EIA assumes. EIA made optimistic assumptions about the number of export terminals that will be built. All of that said, the EIA report is useful because the agency has no axe to grind. It tried to take a static look at a dynamic market. At the end of the day, any forecast is based on a number of assumptions. If any of the assumptions proves off the mark, then the outcome changes. One thing I know is if the price stays low, demand is likely to increase until the price finds a new equilibrium.

MR. AYALI: People in the gas business had a very negative view of the report. The EIA conclusions were at odds with other studies by Deloitte and the Brookings Institution. These other studies suggested the effect of exporting LNG on domestic prices for industrial consumers and for the power sector will not be that significant.

MR. SMITH: These other studies made different assumptions. What really matters is what the marginal cost of production is for that last molecule of gas. It is that simple. A lot of people like to say we have 100 years of supply. That's not what determines the price at any given moment. What matters is whether you can feel confident relying on / continued page 52

US Power Sector

continued from page 51

that commodity over the long term. It is not clear that betting on continued low gas prices is a good idea. Even though the shale gas is now contributing significantly to US gas supply, gas from conventional sources remains something like 67% of US supply. Future supply will depend on how successful people are in developing reserves in different parts of the country and moving the gas to population centers. Regional politics will play a role as will national energy policy.

MR. KOENIGSBERG: US gas reserves are potentially enormous.

MR. SMITH: That's right. The US has potentially enormous reserves that have been known for some time. My point is that the US is not a monolith. Markets are local. You have to move the gas to different markets. This requires infrastructure. Building new infrastructure is never easy. We tend to be too focused on prices at the Henry hub.

MR. SIMON: I disagree with Chris. I think what has changed dramatically in the last five or six years is gas used to be traded in local markets, and while this remains predominantly the case, the price is increasingly being set on the international market. If you look at the guys building export terminals, they are not taking the Henry hub price risk. Their view is they are going to manage a global LNG portfolio. If the price of gas increases abroad, it makes sense to export gas until there is no longer an opportunity for arbitrage profit.

MR. SMITH: I don't disagree with that. My point is that if you are a New York utility trying how to decide how to provide reliable electrical service, you are focused on more than just the natural gas price. You are thinking about the reliability of supply and your ability to build the required infrastructure given local politics. You still have the problem of delivery of gas into the local markets.

MR. CAVICCHI: We have to take a view on pricing. We bring a parade of consultants through our offices. It is amazing how wide the range of forecasts is. You get anything from gas remaining at $2 an mcf to increasing to $4.50 an mcf by 2013.

MR. AYALI: The $4.50 figure is where producers hope to see the price.

MR. CAVICCHI: What else can a gas producer tell his bankers? Gas will be $4.50 an mcf. What does a wind developer tell his bankers? Gas is going to be $5, $6 or $7 an mcf. You can do all the wishing you want. Gas producers are boosting their efficiency at the rate of 30% year over year. This is reducing the cost to drill new wells. A lot of consultants are projecting as little as $3.50 to $4 an mcf as the cost to produce clean gas. The long-term cost curve continues to come down; this all bodes well for exporting gas. It bodes well for finding new uses for gas. I think trucks will eventually run on LNG. Demand will be created in other areas.

Volatility?

MR. SMITH: What has changed more than anything else is the risk-for-return trade off for gas producers. Everyone used to be chasing conventional reserves. You had production curves that showed how the price of gas was going to fall off a cliff. That was the assumption that led to the development of so many import terminals.

Tapping conventional reserves is like letting the air out of a balloon; as the pressure falls, the reserves drop off. Shale is different. You can basically drill a well anywhere from Tuscaloosa, Alabama to Syracuse, New York or from Ohio east to Garrett County, Maryland and, with a relatively high degree of certainty, you will find gas and you know what the production curve will look like. Gas output will peak very quickly and then drop until it levels out. In Kentucky and West Virginia, they have shale gas wells that will produce gas for 70 years. There is less risk associated with drilling a shale gas well.

The other issue is that drilling into a conventional reserve requires building a lot of infrastructure to get the gas to market, but the conventional reserve might only last 10 to 15 years. That means the cost of producing conventional gas is much higher because the cost of the related infrastructure has to be amortized over a much shorter time period. We are seeing a lot of majors move into shale gas. All of this suggests less volatility in pricing.

MR. KOENIGSBERG: Paul Cavicchi, do you agree that we are headed into a period of less volatile gas prices?

MR. CAVICCHI: I worked for a guy who was one of the founders of the independent power business; he talked about a gas bubble for 20 years that never happened. He was very innovative, and I don't mean to criticize him, but gas has been tremendously stable in the United States. The volatility occurred in 2005 when the Gulf Coast was hit by multiple hurricanes. You don't have that OPEC risk with gas. The hurricanes led to about three years of high prices. If you remove them, then gas prices have been relatively smooth. They should remain that way.

MR. KOENIGSBERG: So low volatility.

MR. AYALI: We look at the pricing from a very US-centric perspective. Shale gas is a global phenomenon. Argentina, China and parts of Europe are all producing shale gas, and GDF and other aggregators will have a lot more options for where to find gas supplies. People should take that into account when examining the US market.

MR. KOENIGSBERG: What do you see as the biggest barrier to future production? Is it that there is too much supply in relation to demand? Is it regulatory?

MR. AYALI: I think the industry is taking a breather right now in two respects. First, $2.50 is not a price that gas producers want to see, so they are shutting in production. Those who can afford to do so are sitting back and waiting for prices to increase. Second, the US Environmental Protection Agency came out with new guidelines for shale fracking, and I think people are pausing to digest what EPA said and trying to assess how the different states will react.

Low natural gas prices create more head room for public policy supports for renewable energy without increasing electricity prices.

Opportunity for Renewables?

MR. KOENIGSBERG: How are low gas prices affecting the renewable energy industry? Is there any opportunity for renewable energy producers or are they purely a source of pain?

MR. SIMON: The obvious answer in the short run is that low gas prices are a headwind. The price of wind electricity has been coming down over time. It is becoming reasonably competitive, notwithstanding the low gas prices. Solar prices continue to come down. We have a tendency to look at the world in a static view and underestimate technological changes.

Does a low price of gas help from a perception perspective? No. Will it help from a political perspective, given that we as a country have never had a national energy policy? Does it make it more difficult to argue that renewable energy projects should be subsidized? Maybe.

Do I think there is an ingrained desire for these sorts of technologies to be used as a source of energy? If you ask my kids, they don't pay the bill, so sure, solar, wind, these are all good things. I think that perception is shared by adults in parts of the country, but not everywhere. In at least one state, people are so concerned about global warming that they are prepared to pay as a cost of society to have some diversity in energy sources.

The move to renewable energy will continue and be driven by technology more than anything else.

MR. CAVICCHI: I agree. Low gas prices are a serious headwind in the short term. However, you can argue that it will give governments room to be more proactive with green initiatives. The price of electricity in New England was $70 a MWh. To the extent low gas prices push down the marginal cost of electricity, it creates more head room to introduce public policy supports for renewable energy without increasing electricity prices.

MR. SMITH: There may be a difference between theory and reality. The theory is that what matters are the overall costs, not the specific cost of any one element in the energy supply. Theoretically, with gas prices falling as far as they have, it should be much easier for people to accept subsidies for renewable energy because the cost overall is so much less. But the reality is that people focus on what they are paying for their electricity in any given contract.

MR. AYALI: The interesting thing is prices over the last year have been in the $2 to $2.50 range, and there has still been continued development of renewable energy projects. The question is whether we are at the bottom of the trough and are starting to climb back up as gas prices start increasing again and the price differential narrows.

MR. SIMON: I agree with Paul Cavicchi that there is a trend to want to be green, but the broader question is whether we are ever going to have a coherent energy policy. A patchwork of tax credits, cash grants and state renewable energy mandates is not the most efficient way to do it if you want to build out a segment of the energy market.

MR. KOENIGSBERG: Maybe there is a way for the renewable energy industry and the natural gas industry to work together, which leads me to my next question. Should the renewable energy industry support the exportation / continued page 54

US Power Sector

continued from page 53

of natural gas from this country?

MR. AYALI: The knee-jerk response is to say yes. Anything that increases the price of gas is good for the renewable energy sector, but there are other reasons. You need a coherent energy policy that will help support energy source diversity, and the only way to achieve that in the political environment is to present a sensible, unified approach to it and not make policy what results from individual pressure groups whose efforts will inevitably be perceived as an effort to grab market share.

MR. KOENIGSBERG: Paul Cavicchi, do you share this view?

MR. CAVICCHI: Absolutely.

MR. KOENIGSBERG: Do we think that new gas-fired power plants will end up in rate base or will they be owned by independent generators?

MR. CAVICCHI: I don't see independent generators owning the next wave of gas-fired power plants without long-term contracts from utilities to buy the output, and such contracts are hard to come by.

MR. SMITH: The markets that are in most need of power are the deregulated markets in Texas, New York and New England. There will be an emphasis on developing in those markets. To the extent utilities in those markets have been forced to divest their generating assets and rely on the market to purchase electricity, you will see plants owned by independent generators. In other states, they will go into rate base.

More Export Terminals?

MR. KOENIGSBERG: Roberto Simon, these new LNG export terminals are very costly. Do we think, if gas prices are expected to increase, they will be finished in time to earn a good rate of return?

MR. SIMON: Absolutely. I say that because terminals being built in other parts of the world cost about a third to half of those here to build, but those terminals are one to three years behind the new terminals in the US. Three factors are keys to whether the export business succeeds. They are the capital cost of the terminals, the cost of gas transportation and the price of oil. US LNG is competing against oil-based products to go to Asia and Europe. From 2015, new LNG export facilities will be coming on line in Australia, East Africa and so on.

MR. KOENIGSBERG: Some more views?

MR. CAVICCHI: A lot of companies are willing to bet a few billion dollars on a curve projecting $5 gas in 10 to 15 years, a delivered price for LNG into Asia at $55 to $60 an oil barrel equivalent while oil currently costs from $85 to $100 a barrel and could go higher.

MR. KOENIGSBERG: If the contracts have a pass through of the natural gas price, the change in the price should not adversely affect the LNG export terminal as long as the capacity charge the terminal receives covers the return.

MR. AYALI: The real question is whether the bank market will be there. Cheniere will cost $3.8 billion. Is there enough capacity for two or three of these terminals to be under construction at the same time?

MR. SIMON: The key element is liquidity. There is a ton of liquidity in the market right now.

Cheniere has two trains. It has 4.5 million tons per annum of capacity per train. We will raise close to $3 billion from the commercial bank market alone. There is a ton of money looking for good investments. The guys who are on the sidelines to a degree are the European institutions, but there are a lot of other sources of capital to tap. What Cheniere is demonstrating, and Cameron will demonstrate, is if you have a sound contract structure for a project, there is capital to be found. The money will come from banks, the capital markets, the export credit agencies, Chinese banks, Korean banks. There is no shortage of liquidity. Money is not as cheap as it used to be, but capital is readily available. ◎

Governments Move to General Principles to Combat Aggressive Tax Planning

by Paul White, in London

For several days in the early summer, the news media in the United Kingdom were dominated by the apparently shocking revelation that a well-known TV comedian had not been paying "enough tax." Tales of show business personalities deliberately or naively underpaying tax are fairly common on both sides of the Atlantic, but this was something different.

When the story first broke, the comedian involved, Jimmy Carr, initially put up a robust defense saying, "I pay what I have to and not a penny more." But as the news coverage developed, it became apparent that he had been involved in arcane but, according to Mr. Carr's advisers, entirely legal arrangements to reduce his effective tax rate from 50% to just 1%. Even US presidential candidates apparently stop with the tax planning at 13%.

In broad terms this remarkable result was achieved by directing what might otherwise have been his taxable income from his lucrative UK appearances to a corporate service provider established in a tax haven. What happened to the funds offshore has not been made public, but it is likely that the bulk of the income was paid into a form of unregulated pension fund. Mr Carr's financial requirements in the UK were then met by long-term loans from the offshore fund that were not taxed as income in Mr. Carr's hands because of his contingent liability to repay the amounts advanced. It is unclear whether any of the parties seriously expected those loans ever to be repaid.

The BBC reported that Mr. Carr was just one of around a 1,000 UK residents using the scheme, which had been marketed under the hubristic title "K2," to shelter almost £170 million from tax each year, but it is unlikely that many Britons found these disclosures surprising. There seems to be an assumption in the national psyche that the wealthy enjoy benefits that are not available to the general population. But what made Mr. Carr's position unusual, and perhaps explains why the media chose to make an example of him in particular, is that in his comedy performances he commonly rails against just the sort of behavior of which he was now accused. In a recently broadcast satirical sketch, he had even lambasted one of the high street banks for its role in exactly the same sort of offshore tax planning.

Within 24 hours Mr Carr apologized to the world (via Twitter, of course) for using the offshore arrangements calling it a "terrible error of judgment," but not before the usual media pundits and a few politicians, including the prime minister, David Cameron, had come out to condemn Mr Carr's tax planning at this time of national austerity as "morally wrong."

Cat and Mouse?

Poor Mr. Carr; despite the hysterical media coverage, the majority of judicial and expert opinion is on his side and most tax professionals would strongly disagree with Mr. Cameron's implied assertion that there is a moral aspect to taxation. To talk about the morality of tax assumes that for every person or transaction, there is an objective 'right amount of tax' that should be paid, but if that were true, we would not require tax laws at all and our tax lawyers would need to be moral philosophers.

Which of us can honestly say that if the law did not require us to pay tax we would pay it voluntarily? The imposition of tax is entirely law based in the same way as sports and even driving on the roads are based on systems of rules and regulations.

But, in addition to the rules, some games have something extra, the unwritten "spirit of the game" that has developed over time and is, in a sense, the morality of the game. There is nothing similar in relation to driving so, in the UK at least, the highway code creates a morality of the road by including an express rule that, "you must not drive without due care and attention . . . [or] . . . reasonable consideration for others." Could something similar be done in relation to the tax code?

Many tax professionals talk about their relationship with the tax authorities as though it were a chess game or even a game of cat and mouse. Can it really be "morally wrong" for Jerry to outwit Tom?

General Anti-Avoidance Rules

From the UK government's perspective, the timing of the K2 story could hardly have been better in that it came just a few days after the government commenced consultation on the introduction of a general anti-avoidance rule or GAAR. Past attempts to introduce a GAAR have always stalled, but now minsters could point to a front page example of egregious tax avoidance that a GAAR would target.

Although the process has only just begun, it is only a consultation on the detail of the scheme. There is very little doubt that the GAAR will be introduced in 2013, and the majority of the draft legislation is already publicly available.

GAAR would write a general principle into the UK tax law that the government may set aside any arrangement where "if, having regard to all the circumstances, it would be reasonable to conclude that the obtaining of a tax advantage was the (or a) main purpose of the arrangement."

UK tax legislation already includes numerous targeted anti-avoidance rules, many of which use similar concepts of "tax avoidance" but each of which applies only to a particular area of the tax code tax. The introduction of a GAAR would allow some of the targeted anti-avoidance */ continued page 56*

GAAR

continued from page 55

rules to be repealed, but most are likely to remain because the GAAR will have a higher hurdle for its application. In many cases, targeted anti-avoidance rules will apply if the taxpayer undertakes a transaction with the sole or main purpose of avoiding the particular part of the tax code; by contrast, a tax-driven arrangement would need to be demonstrably "abusive" in order for it to be challenged under the GAAR.

A number of other countries are moving to adopt their own forms of GAAR. They include Canada, Australia, New Zealand, Germany, France, South Africa and India. The United States moved in the same direction by imposing a general requirement by statute in 2008 that transactions must have "economic substance." US tax lawyers are now sparring with the tax authorities over whether the government needs to issue an "angel" list of types of transactions that companies need not worry will be found to lack such substance.

A representative of the firm that marketed the K2 scheme is reported to have told a seminar of businessmen: "The Revenue closes one scheme, we find another way round it." Although rules are in place to require most tax schemes to be disclosed to Inland Revenue, the government is still playing catch up, changing the rules to close down schemes after they have already been used. The main benefit of a GAAR from the government's perspective is that it will enable the government to get ahead of the game in challenging the most egregious forms of avoidance.

Implementation

The GAAR will augment the interpretation of the letter of the tax law by giving Inland Revenue and the courts the ability to consider transactions against the broader purpose of the tax legislation. Consequentially, the GAAR is expected to be most effective where the principles underlying specific tax rules are clear.

For older legislation there is a recognized difficulty with this approach because of the need first to identify the purpose of the rules. If all a court has to look at is the black letter of the law, it is arguably being asked to identify what Parliament intended to say in order to "improve" what it actually did say. In that case, the court would be at risk of making law.

However, in recent years, there has been a deliberate move towards purposive legislative drafting so that new tax legislation often commences with an acknowledgment of what it is intended to achieve. Although there may still be technical issues with the interpretation of such purposive drafting, because courts will continue to be loath to make good the failings of the legislature, it undoubtedly lays the ground for the application of a GAAR that looks to apply the principles and purpose of the tax code.

The GAAR will operate in relation to individual income tax, corporation tax and most other tax charges in the UK except value-added tax.

The government has also indicated that the GAAR will be used in the interpretation of double tax treaties which, it says, is consistent with the OECD model commentary. Where the GAAR applies, the tax authorities will be able to counteract the planned tax avoidance by taxing the abusive arrangement on a "just and reasonable" basis.

At first sight, the ambit of the GAAR appears to be very wide. An arrangement can be set aside if "obtaining of a tax advantage was the (or a) main purpose of the arrangement." The reference to a "main purpose" is familiar from the existing targeted anti-avoidance rules, and Inland Revenue's view is that any purpose that is more than incidental is a main purpose.

However, the GAAR is only intended to catch "highly abusive contrived and artificial" schemes, so its reach is reduced by a double reasonableness test in relation to whether a particular arrangement is abusive.

A tax arrangement is only abusive if, having regard to all the circumstances, "entering into or carrying out the arrangement cannot reasonably be regarded as a reasonable course of action." The consultation document provides a useful guide to how the GAAR should operate. It says "the GAAR is intended to be capable of altering the tax consequences of abusive arrangements if the consequence claimed is one that manifestly would not have been countenanced by Parliament."

Broadly, the question to be asked of any tax scheme is, "what would Parliament have said if it had known the rules would be used like this?"

The introduction of the GAAR will undoubtedly change the nature of aggressive tax planning in the UK, but it is unlikely to encroach significantly on the sort of tax planning undertaken by the majority of businesses and entrepreneurs. Ironically, it is even arguable that the K2 scheme would not fail the double reasonableness test, so if it survives challenge under the current law, it would not, in any case, be susceptible to the GAAR. ◎

Environmental Update

SO_2 and NO_X

Power plants in 28 US states, mostly east of the Mississippi River, received a reprieve in late August from a US appeals court.

The court struck down a federal cross-state air pollution rule also known as CSAPR that would have required certain power plants to reduce sulfur dioxide and nitrogen oxide emissions. The US Environmental Protection Agency estimated that CSAPR would have helped reduce SO_2 emissions by 73% and NO_X emissions by 54% percent by 2014 as compared to 2005 emissions.

A US court struck down new federal limits on SO_2 and NO_X emissions, but left slightly older limits in place.

The court ordered the government to continue administering a clean air interstate rule in the meantime that, according to government estimates, would reduce SO_2 emissions by 57% and NOx emissions by 61% below 2003 emissions. The clean air interstate rule has been on the books since 2005, but in December 2008, a court found fault with it as well and sent it back to EPA with instructions for the agency to find a replacement. CSAPR was to be the replacement.

EPA has 45 days to seek a rehearing in the US appeals court or appeal to the US Supreme Court. An appeal to the US appeals court would not be surprising given the scathing dissenting opinion written by one of the three US appeals court judges who heard the case. The court struck down CSAPR on a 2-1 vote.

CSAPR was an attempt by the federal government to address complaints by eastern states that are downwind from large power plants in the coal belt in the Midwest. It set emissions caps that would have required reductions in SO_2 and NO_X emissions from existing power plants in 28 states, mostly east of the Mississippi River, but as far west as Texas. CSAPR was originally scheduled to take effect January 1, 2012, but was delayed by the court pending resolution of the legal challenges. In the meantime, a predecessor rule, the clean air interstate rule, remained in effect.

Prior to the court ruling, EPA expressed confidence that CSAPR would be upheld; however, the court found that the agency exceeded its statutory authority and held that the rule might have required some states to reduce emissions by more than their significant contribution to downwind states' nonattainment with national ambient air quality standards and that EPA impermissibly issued federal plans to implement the rule without allowing states the opportunity first to issue state plans to implement the rule. The court ordered EPA to continue administering the prior clean air interstate rule until EPA provides a replacement, which could take years.

In the meantime, there may be ramifications to already-approved state implementation plans and other EPA rules that assumed they were building on pollutant reductions anticipated under CSAPR. This will take a while to sort out, but will need to be monitored.

Greenhouse Gases

The same US appeals court upheld a number of Environmental Protection Agency rules in late June for limiting the emission of six greenhouse gases from vehicles and stationary sources like power plants.

In a broad, but not entirely unexpected win for EPA, the court held that the agency's finding that greenhouse gases endanger public health and welfare and its regulation of greenhouse gases emitted from cars and light trucks are neither arbitrary nor capricious. The court then upheld various long-standing EPA interpretations of the Clean Air Act that require power plants and other stationary sources of greenhouse gases to obtain permits. Finally, the court rejected challenges to the EPA regulations that narrow application of greenhouse gas */ continued page 58*

Environmental Update

continued from page 57

permit obligations based on the petitioners' lack of standing to challenge them.

The US Supreme Court held in 2007 in *Massachusetts v. EPA* that EPA has the authority to regulate greenhouse gases as pollutants and ordered it to determine whether greenhouse gases endanger public health and welfare. After the agency concluded there is such endangerment, industry and various states challenged the finding based largely on arguments that EPA lacked sufficient scientific support and failed to conduct a cost analysis.

The appeals court rejected these arguments, holding that EPA met its threshold burden to regulate greenhouse gases because EPA "compiled a substantial scientific record" that greenhouse gases "very likely caused warming of the climate over the last several decades" and increased the risk of extreme weather events, changes in air quality, increases in pathogens and other dangers to human health and welfare.

Once EPA determined that greenhouse gases endanger human health and welfare, EPA had a "non-discretionary" duty to regulate emissions of greenhouse gases from motor vehicles. Accordingly, the court dismissed the petitioners' challenges to the regulation limiting emissions from tailpipes of cars and light trucks. Of note, the auto industry intervened in the case to support the tailpipe rule during this litigation because of that industry's preference for uniform federal regulation as opposed to a state-by-state approach.

Under EPA's longstanding interpretation of the Clean Air Act, once the agency began regulating vehicles, the agency was also required to regulate greenhouse gases from stationary sources under two permitting programs called "prevention of significant deterioration," or "PSD," and "title V." The court agreed the application of these permit programs to stationary sources such as power plants were "statutorily compelled: a source must obtain a permit if it emits a major amount of a regulated pollutant."

To ease the regulatory burden of the new permitting obligations, EPA issued two additional rules that limited the scope of when and to whom such permitting obligations apply.

First, EPA concluded that an air pollutant becomes subject to regulation under the Clean Air Act only when a regulation requiring control of that pollutant takes effect. Therefore, it delayed the effective date of the greenhouse gas permitting programs' application to stationary sources until the tailpipe rule takes effect.

Second, EPA limited the application of the PSD and title V permitting programs to only the largest industrial sources, raising permitting thresholds for greenhouse gases above that of other regulated air pollutants. Specifically, in what is known as the "tailoring rule," EPA set the greenhouse gas permitting threshold at 100,000 tons per year of greenhouses gases because it determined the 100/250 tons-per-year threshold in the Clean Air Act would have resulted in "absurd results" by triggering permits for millions of sources.

The court declined to reach the merits of either rule on grounds that the petitioners failed to demonstrate standing to challenge the rules in court. The court said neither the industry nor the state litigants could prove they were injured by rules designed to reduce the number of sources subject to permits. The delay in when the new restrictions take effect and the decision to limit them to larger emitters of greenhouse gases "actually mitigate petitioners' purported injuries," the court said.

Nearly a hundred lawsuits were consolidated into *Coalition for Responsible Regulation. et. al. v. EPA*, the name of the case before the US appeals court.

The case was heard by a three-judge panel; all three agreed with the decision. Opponents of the rules asked the full court in August for a rehearing.

Mercury

The US Senate rejected a move in June by Senator James Inhofe (R-Oklahoma) to bar implementation of a new rule that will require certain coal- and oil-fired power plants to reduce mercury emissions starting in 2015.

The rule also revises "new source" performance standards for new coal and oil-fired power plants that limit emissions of particulate matter, SO2 and NOx.

The vote was 53 to 46 and proceeded largely along party lines, with five Democrats joining 41 Republicans in voting to override the Environmental Protection Agency. Two independents, five Republicans and 46 Democrats voted to let the EPA proceed.

The rule is called "Utility MACT" by the environmental community. EPA issued the Utility MACT rule in December 2011 in response to a court-ordered deadline to which EPA agreed in a settlement with environmental and health advocacy groups in *American Nurses Association v. Jackson*. The rule does not apply to natural gas-fired power plants unless the gas is produced by gasifying coal or oil. The rule limits the amounts of not only mercury, but also arsenic, chromium, dioxins, lead, formaldehyde and other substances that may be emitted from power plants and requires use of "maximum achievable control technology" or MACT to control such emissions at power plants larger than 25 megawatts in size that burn coal or oil.

The rule offers some flexibility to utilities that need more than the three years that the Clean Air Act allows for installing the required air emissions control technology. The first year of compliance is 2015, but a presidential memorandum clarifies that regulators can invoke existing authority under the Clean Air Act to provide a one-year extension if companies can demonstrate that extra time is needed. EPA can also use its enforcement discretion to grant a fifth year to comply by issuing an administrative order or entering into a consent decree with a particular facility. The office of enforcement and compliance assurance at EPA released a memorandum outlining how utilities can obtain compliance extensions.

The same court said the US Environmental Protection Agency can regulate greenhouse gases without requiring further action by Congress.

Critics of the rule argued that more time would reduce the cost of compliance by allowing retirements and retrofits to take place in a more sequential manner and providing time to address potential grid reliability issues while still achieving the EPA's objectives. Critics also argued against consent decrees and administrative orders as a means of obtaining extensions to comply both because companies issued them might be seen as being in violation of the Clean Air Act and because entering into consent decrees could put them at risk of citizen suits for noncompliance.

Since the vote, the EPA agreed to reconsider portions of the rule. The agency has until November 2, 2012 to complete its reconsideration.

Eagles

The US Fish and Wildlife Service is weighing changes to its regulations on programmatic permits to "take" bald and golden eagles. The agency collected comments through mid-July.

A "programmatic" permit is a permit allowing multiple takings over a long period or in locations that cannot be specifically identified, like a wind farm with turbines.

The Bald and Golden Eagle Protection Act makes it illegal to "take" bald and golden eagles unless otherwise authorized. The word "take" means to "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, destroy, molest or disturb." The term "disturb" is defined in turn under the US Fish and Wildlife Service regulations as any action "to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior."

Violators risk civil penalties and jail time of up to one year for the first conviction. Felony convictions could result in significantly higher fines and up to two years of jail time. Having a programmatic take permit can shield the holder from enforcement provided that any take is within the permitted limits.

The US Fish and Wildlife Service was authorized to issue programmatic take permits starting in 2009 where the take is associated with, but not the purpose of, an activity. The permits are effective for up to five years at a time. Obtaining this type of permit triggers the National Environmental Policy Act, which requires a review of the environmental effects of a particular project. This means that many projects that normally would not trigger / *continued page 60*

Environmental Update

continued from page 59

National Environmental Policy Act in the past — for example, because they are on private land with no federal nexus — need to go through the National Environmental Policy Act environmental review process. This process can be time consuming. So far, only one wind energy project has obtained such a permit.

The proposed changes to the permit process include the following. The government is considering extending the permit term from five years to 30 years. It is considering letting permits be transferred where a project is sold to a new owner rather than requiring a new permit.

The fees associated with programmatic permits are expected to increase substantially. A wind farm seeking a programmatic permit with a 30-year term would have to pay an upfront fee of $51,600 ($36,000 for the permit application and $15,600 for administration of the permit over its term), $1,000 for a permit amendment and $1,000 for a permit transfer. In the past, a permit with a 5-year term required fees of $1,000 for the application, no administration fee and $500 for a permit amendment.

So far, lenders appear in no rush to require projects to obtain programmatic permits, although a longer permit term may make this option more attractive to lenders concerned about potential enforcement risk.

— contributed by Sue Cowell and Andrew Skroback in Washington.

Chadbourne & Parke LLP

New York
30 Rockefeller Plaza
New York, NY 10112
+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

Kyiv
25B Sahaydachnoho Street
Kyiv 04070, Ukraine
+380 (44) 461-7575

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

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

Beijing
Beijing Representative Office
Room 902, Tower A, Beijing Fortune Centre
7 Dongsanhuan Zhonglu, Chaoyang District
Beijing 100020, China
+86 (10) 6530-8846

www.chadbourne.com

00-100 | 12-09 PF NewsWire September 2012