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Strategies for Starting Construction

by Keith Martin and John Marciano in Washington, and Eli Katz in New York

The race is on to get renewable energy projects in the United States under construction by year end to qualify for cash grants from the US Treasury.

Developers are pursuing different strategies.

It is not enough merely to have made a large down payment toward turbines, modules or other equipment for the project by year end. A senior Treasury source said the government is looking for economic activity during 2010. A developer must show work at the site or at the factory on equipment for the project during 2010.

The grants are 30% of the project cost and are paid on new wind, solar, geothermal, biomass, landfill gas, waste-to-energy, ocean energy and fuel cell projects that are completed in 2009 or 2010 or that start construction in 2009 or 2010.

Grants of up to 10% of project cost are also paid on small cogeneration facilities of up to 50 megawatts in size.

Projects that merely start construction in 2010 must be completed by a deadline. The deadline is 2012 for wind farms, 2016 for solar, small cogeneration and fuel cell projects and 2013 for other types of projects.

Congress may ultimately give companies more time. A bill in the House would give developers another two years through December 2012 to start / continued page 2

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UNCERTAIN TAX POSITIONS will have to be flagged on US tax returns starting this year using a new form the Internal Revenue Service released in mid-April.

The form — called a Schedule UPC — will have to be attached to corporate tax returns filed for 2010.

The IRS hopes that forcing corporations to disclose tax positions about which they are uncertain will save the government time in tax audits. Critics speculate that IRS agents will be able to save even more time by simply disallowing all the positions a company identified.

The forms will have to be filed for now only by / continued page 3

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construction without changing the deadlines to complete projects. However, the odds of such an extension at this point are probably a little better than 50%. Most developers are taking steps to start construction in case there is no extension.

Two Ways

The Treasury Department explained what it means to start construction in written guidance on March 15. The guidance left many unanswered questions. The Treasury answered some of the questions since then in private meetings and in public statements at industry conferences.

It is not enough merely to have made a large down payment for equipment by year end.

There are two ways to show construction started.

One is to show there was "physical work of a significant nature" on the project during 2010.

The Treasury said that "the beginning of excavation of the foundation, the setting of anchor bolts into the ground or the pouring of concrete pads of the foundation" at the site count as such work. It also counts if physical assembly of major components starts off site at a factory. However, the developer must have a "binding" contract in place before such work starts in order to count work done by an equipment supplier or other contractor.

To be "binding," the contract must be more than an option to choose equipment later. The Treasury said "the amount and design specification of the property to be purchased" must be clear from the contract. The contract should not limit damages if the developer walks away to less than 5% of the contract price. Any conditions to performance by a party must be outside the control of the parties. Thus, for example, if the developer must give a notice to proceed before the contractor will start work, the notice should be given before year end.

It is not clear whether a contract between related parties can be "binding." It is best to assume not.

There is a risk that amending the contract after work starts could lead to loss of grandfather rights. The guidance suggests that it does, but the Treasury may still be thinking about this issue. The guidance said that any amendment must be "insubstantial." Minor modifications in design are not a problem; an example is the later addition of a "cold weather package for wind turbines." The IRS used a similar standard in 1986 after the investment tax credit was repealed. Projects that were under binding contract before the repeal to be built still qualified for an investment credit provided there was no "substantial modification" of the contract later. An amendment that increased the contract cost by more than 10% was considered substantial.

Ellen Neubauer, the cash grant program manager, said at a wind industry finance conference in New York in early April that it is the start of physical work of a significant nature to construct roads on the project site. The roads must be used to transport equipment rather than solely to provide access for people working at the site.

She said it is also the start of physical work for the developer to lay three concrete pads for a wind farm that will consist of 65 turbines or for the turbine vendor to commence physical assembly of at least one turbine for the project at the factory under a binding turbine supply agreement signed before physical assembly starts.

It is not clear whether it matters if work starts in 2010 but then nothing is done for another year at the site or at the factory on the turbine order. Some senior Treasury staff are not bothered by such a delay; they stress that the Treasury guidance said all that is required in 2010 is the "beginning" of construction or else they view the deadline to complete the project as a check on how long a delay is possible. However, there may be a risk if the facts show with hindsight that construction did not truly get underway.

Developers who plan to rely on physical work to start construction plan to work steadily once construction starts, although possibly at a slower pace than normal. For example, a wind farm that might normally take six months to construct might take 12 to 18 months under an elongated construction schedule.

There is an assumption in each of these cases that the developer will choose to treat all the turbines or solar arrays as a single "property" so that the work done in 2010 counts as the start of work on the entire project. The Treasury treats each turbine or solar array that can operate independently as a separate property. Therefore, work must start independently on each. However, a developer can choose to treat multiple turbines or solar arrays that are owned by the same company and are on the same site as a single project.

5% Test

The other way to show that construction started is to "incur" more than 5% of the total project cost by December 2010.

A developer does not have to satisfy both the physical work test and the 5% test; either is enough.

Costs are considered "incurred" when the developer pays them, but only if he expects the equipment or services for which payment was made to be delivered within 3 1/2 months after payment. Otherwise, he must wait until delivery to count the costs. Thus, for example, a payment made on December 31, 2010 counts in 2010 as long as the equipment is reasonably expected to be delivered by April 15, 2011. Otherwise, the payment is treated as spending in 2011 after delivery in 2011. Delivery may include transfer of title to equipment that has been manufactured, but that the manufacturer is holding in storage at the site.

The developer can look through any "binding" contracts with equipment suppliers or other contractors that are signed before manufacture of the equipment or other work starts and count spending by the contractor using the same principles. Thus, for example, the developer can count spending by a turbine vendor on components or services, but the spending counts at time of payment only if it is reasonable to expect delivery of the components or services to the turbine vendor within 3 1/2 months of payment. Otherwise, costs are incurred only as equipment or services are delivered to the vendor. This will require getting equipment suppliers to certify how much they spent toward manufacture by year end this year.

To show how this works, suppose a */ continued page 4*

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corporations that issue audited financial statements and have at least $10 million in uncertain tax positions and also have assets of at least $10 million. The IRS said it will decide later when partnerships, real estate investment trusts and tax-exempt entities must start filing.

The instructions for the form indicate the agency is looking only for tax positions for which the company recorded a reserve in an audited financial statement or decided not to record a reserve based on an intention to litigate.

Positions do not have to be reported that were taken on past tax returns for tax years beginning before December 15, 2009 or in short tax years that started after December 15 and ended by December 31, 2009.

The form requires the company to describe each uncertain position concisely, list the sections of the US tax code that are involved and show the maximum amount the company would have to pay in additional taxes if the position were disallowed. The potential tax liability is calculated by assuming a 35% tax rate and ignoring any net operating losses or tax credits that the company might be able to use as shelter.

The form is a draft. The agency asked for comments by June 1. The draft form and instructions were released as part of Announcement 2010-30.

CALIFORNIA will no longer tax cash grants that the US Treasury pays on new renewable energy projects.

The grants are 30% of the project cost and are paid 60 days after a wind, solar, geothermal, biomass or other renewable energy project is first placed in service. They are only paid on projects that are completed in 2009 or 2010 or that start construction in 2009 or 2010.

The State Franchise Tax Board had said that grants paid on such projects in California are subject to franchise taxes at an 8.84% rate. Governor Schwarzenegger */ continued page 5*

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developer signs a binding turbine supply agreement in mid-2010 for turbines to be delivered in late 2011 and makes a 20% down payment. The turbine vendor then spend 15% on components for the turbines. The developer cannot count the 20% down payment in 2010, but can count the 15% spent by the turbine manufacturer provided the manufacturer expects delivery of the components within 3 1/2 months of payment.

The manufacturer would also have to link the components to the turbines ordered under the contract.

Two large wind turbine manufacturers told the Treasury at a meeting in early April that it is impossible to certify that components ordered this year are for particular turbines that will be manufactured next year or the year after. One said that components are ordered well in advance of use based on expected orders. Ninety-five percent of the components in a turbine are interchangeable across turbine types. The manufacturer said components are not assigned to a particular turbine until roughly a week before manufacture starts. Actual manufacture of the turbine takes five days.

This has caused wind developers to take a harder look at starting physical work at the site or else requiring manufacturers to manufacture at least one turbine for each project in 2010 in order to commence construction under the physical work test.

The developer must incur more than 5% of the actual project cost, not the expected cost in 2010. A developer would be wise to incur more to leave a margin for error. However, it may be possible if project costs spiral to fix the problem by choosing not to include one or more turbines or solar arrays as part of the project on which a cash grant is taken. For example, the developer has the option in a 65-turbine wind farm of treating 63 turbines as one project and two turbines as a separate project.

Other Issues

The Treasury is still thinking about several issues. They may be addressed in questions and answered posted to the Treasury website. Any such answers are unlikely to be posted before June.

The Treasury has not sorted out how to deal with frame or master agreements that larger wind companies use to buy turbines for multiple projects. The agreement is usually signed by a parent company. Closer to the time turbines are manufactured, "daughter" contracts are signed with project companies essentially designating turbines for use in particular projects and copying over the terms from the master agreement into each standalone contract. Among the issues are whether spending by the parent company carries over to the subsidiary and by when turbines must be designated for use in particular projects.

The Treasury is looking for a way that it can confirm to developers that they started construction. A developer can apply for a grant after starting construction, but before the project is completed. The Treasury said last year that it planned to respond in such cases whether it agrees the project is under construction. However, it has not sent any such confirmations to date despite receiving more than 100 applications. In all the cases to date, the agency concluded that the projects would be completed by December 2010 so it was a moot issue when construction started. Whether it is able to send such confirmations in the future is a resource issue. It is looking into what is possible.

Developers should ask equipment suppliers to certify to spending or the start of physical assembly as soon after the threshold for starting construction is reached in 2010, and then the developer should apply to Treasury for a grant. This may leave time to fix any problems before year end if the Treasury responds promptly. Even if the response is not received until early 2011, at least the issue whether construction started in time can be taken off the table.

Geothermal companies that started drilling before 2009 for power plants that will not be completed until after 2010 received some relief in March. The Treasury said that it is not the start of physical work on a project to do "test drilling of a geothermal project." It also said that a developer "may treat physical work of a significant nature as not having begun until more than 5 percent of the total cost of the property has been paid or incurred."

Senior Treasury staff told Chadbourne at the same time that it is the start of physical work on a geothermal power plant to drill a fully-functioning production well whose output will be dedicated to the power plant. An example of such a well is one drilled to production depth and diameter and for which permanent casing, a tree or other above-ground equipment and flow controls have been installed and tested. ◎

Germany Cuts Solar Subsidy

by Dr. Till Vogel, with Schiedermair Rechtsanwälte in Frankfurt

The German federal cabinet decided in early March to reduce feed-in tariffs for newly-built solar photovoltaic projects in Germany by an average of 15% starting July 1, 2010. Another 9% is already scheduled to take place on January 1, 2011.

The plan must still be approved by the Bundestag, or the German parliament. Some changes are possible before the bill implementing the plan is approved

The lower tariffs will apply to projects that go into service on or after the dates set for tariff reductions.

The tariffs were already cut by 9% at the start of 2010. They currently run from 37.14¢ to 28.43¢ a kilowatt hour depending on the size of the project and its location. The feed-in tariff is the amount that utilities in Germany are required by law to pay for electricity offered to them — in this case from photovoltaic facilities. Total installed generating capacity from solar in Germany is 8,877 megawatts from photovoltaic installations. There are currently no concentrating solar power projects (also known as solar thermal). The tariff is the same for both types of solar.

The feed-in tariffs have been declining over time, but they normally decline only once every year. When Germany first instituted them in 2000, they were 62.4¢ per kWh.

The latest plan would lead to a total reduction in the feed-in tariff for PV energy of almost 30% within a 13-month period. As the feed-in tariff is guaranteed by law for the year of the connection to the grid plus the following 20 calendar years, the amount is important for financing PV projects. The latest measures mean a significant loss of revenue over 20 years if a project starts too late.

Reductions Vary

The feed-in tariffs for electricity generated in roof-mounted solar systems will be reduced by 16% if the system is connected to the grid after June 2010. The relevant date for the calculation of the feed-in tariff for a German PV project under the regime of subsidies is the day of the first power supply into the grid. Thus, commencing power sales on July 1 rather than June 30 can cost a developer a lot of money.

The reduction of the feed-in tariffs for / continued page 6

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signed a bill to waive the taxes in early April.

The bill is not effective until January 1, 2011, but will be retroactive to 2009 and 2010 once it takes effect. The Franchise Tax Board said in the meantime that it does not plan to collect taxes on grants paid in 2009 and 2010.

WYOMING will start collecting an excise tax of $1 a megawatt hour from wind generators in the state. The tax will apply to electricity generated after 2011. It will apply on a turbine-by-turbine basis, but will not be collected until the turbine has been in use for at least three years.

The state legislature debated setting the tax at anywhere from a penny to $5 a mWh before settling on $1. It delayed the effective date to allow time to study the potential effect on the wind industry.

INDIA reaffirmed in late March that companies based in Mauritius do not have to pay capital gains taxes when they sell shares they own in Indian companies.

An E*Trade subsidiary in Mauritius sold shares in an Indian company to an HSBC investment vehicle also in Mauritius. The sale generated a long-term capital gain for E*Trade. The Indian authorities challenged E*Trade on its position that it was entitled to an exemption from capital gains taxes in India under article 13(4) of the India-Mauritius tax treaty, which says that a Mauritius resident can only be taxed in Mauritius on its gains, arguing that the E*Trade subsidiary in Mauritius was merely a shell company and the real owner of the shares in the Indian company was the E*Trade parent company in the United States. The Indian authorities directed HSBC to withhold 21.11% of the sales price for the capital gains taxes. E*Trade appealed.

The Authority for Advance Rulings held that India had to honor the treaty exemption, ruling essentially that there is no prohibition against treaty shopping. It also / continued page 7

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electricity from ground-mounted PV systems installed on so-called redeveloped areas -— for example, former military sites or former landfills -— is not as painful as for roof-mounted systems. The reason for this is purely political. The intention is to promote the use of such real estate for PV systems as they are of limited use for other purposes. Furthermore, the investors run the risk of having to deal with environmental pollution on such sites. Thus, the reduction of the feed-in tariffs for projects in such locations is only 11%.

For other areas, the tariff will be reduced by 15%.

Feed-in tariffs will be eliminated for ground-mounted PV systems installed in areas that are defined as "farm land." This has been a subject of intensive discussion. Opponents argue that it is unethical to produce electricity on land that could feed humans while people starve and prices for food rise. From July 1, 2010 on, there will no longer be an obligation for grid operators to buy and remunerate solar companies using "farm land" to generate electricity. Since there are a lot of projects already in the pipeline, there needs to be a transition arrangement for these projects. The bill provides "grandfather" relief. The current tariff would continue to apply to projects that are already in an advanced stage of development, were approved by the local authorities by an official development plan before the end of 2009 (although this date is currently under discussion) and will be built and connected to the grid by the end of 2010.

In order to compensate for the loss of "farm land" for solar development, the cabinet suggested that trade and industrial areas as well as areas along motorways and railways (the latter in 100- to 200-meter-wide strips) should be included on the list of areas on which PV systems can claim special promotion under German law. Systems in such areas will be eligible for the feed-in tariff in the future.

Although such changes in the guaranteed feed-in tariffs have been foreseeable since the current black-yellow government formed its coalition in Berlin, the amount of the reduction is surprising.

Also the complete ban of ground-mounted PV systems on "farm land" was unexpected.

The German PV industry now claims that it is being strangled and that the number and size of new PV projects in Germany will drop significantly with a cost of thousands of jobs in the national PV industry. The government responds that since the price of solar power equipment (especially solar modules) dropped significantly during the last 18 months, solar projects have become more profitable leading to an "over-promotion" of new projects by the current tariffs.

Under the German law, the local grid operator has to connect every PV plant to its grid and to purchase all electricity generated as well as to pay the feed-in tariffs provided for by law. German law guarantees a constant feed-in tariff for the year in which the plant starts to supply electricity into the grid and the following 20 calendar years. The details are in an "Act on Granting Priority to Renewable Energy Sources." The grid operator can pass through all these amounts to its customers as an add-on fee to the regular electricity invoices. Thus, the subsidies are paid ultimately by all electricity consumers in Germany. To the extent electricity from solar costs more than from other sources, this becomes a burden on the German economy. The current German government wants to slow the rate at which Germany is adding to this burden by cutting tariffs which, in turn, will mean fewer new projects.

Lobbyists from the solar industry have mobilized and are working on the politicians from both partners of the black-yellow coalition in Berlin. These efforts have already met with some success: only two weeks after the declaration by the federal cabinet, the prime minister of Bavaria — which is one of the southern states and thus hosts more solar projects than any other state in Germany — demanded changes in the federal plan. Perhaps surprisingly, it appears that the coalition is willing to follow this demand and will provide for a longer transition period to allow projects that are currently under development to be completed under the existing tariff. More changes are possible before any plan is adopted by the Bundestag.

Significance?

So what does all this mean for investors and banks who are engaged in the PV business in Germany?

For those who have German PV projects in the pipeline, the best advice is to watch the legislative process closely and try to qualify for grandfather relief under whatever transition rule is adopted. Currently the bill states that PV plants already operating are not affected at all by the changes. It should be safe to assume that this will not change. Any retroactive reduction in tariffs would be declared unconstitutional by the federal constitutional court.

Also, PV plants that start to feed energy into the grid before the key dates (July 1, 2010 or possibly October 1, 2010) will not be affected by the changes for the same reasons.

Only plants that start to feed electricity on or after July 1, 2010 (or whatever date is chosen ultimately) are affected by the new tariffs. As the construction period for a PV project is in some cases longer than the three months remaining until July, this means that some projects that were planned, calculated, funded and developed under the old feed-in regime could be hit hard. Developers in such a position will have to decide whether to start construction or cancel their projects.

To soften the hardship, the bill grants a grace period for very large countryside projects that are already under development. Such projects can be built and connected to the grid until the end of this year and still receive the existing feed-in tariff until 2030 if the competent local parliament had already agreed to the project by December 31, 2009 and has granted the permission to build the plant. However, for all other types of PV projects, especially the very popular roof-mounted systems, this transition rule will not apply. Therefore, there is now tremendous time pressure to finish construction of these projects before July 1, 2010. In case of some large projects, this will not be possible.

Upside

The bill is not only a one-way street. It increases some subsidies.

Under the current German regime, there is a financial incentive for owners of smaller PV plants (such as private households) not to feed the electricity into the grid but to use the energy for themselves on site. If an owner does so, he receives an incentive payment from his grid operator. The owner receives this money and also avoids having to buy electricity from the grid. Thus, householders are better off than if they sold to the grid. The bill increases this incentive from 3.6¢ to 8¢ per kWh. The incentive will also be extended to larger PV systems with outputs of up to 800 kilowatts. However, the incentive payments to owners of such larger systems are reduced to the extent the price the homeowner would be charged to buy electricity from the grid is less than 20¢ a kWh. This is the benchmark price in the bill.

Further reductions in the feed-in tariff will occur at the rate of 9% a year. However, the rate could increase to 11% a year if additionally installed PV capacity reaches 3,500 megawatts a year. The national target for / continued page 8

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questioned the continuing viability of the treaty.

The Mauritius treaty used to confer two benefits. One was a reduced withholding tax on dividends received from Indian companies. The other is an exemption from capital gains taxes. India cut off the withholding tax benefit by converting its withholding tax to a tax on the Indian company paying the dividend. It has periodically fought exemption claims on capital gains taxes.

In 2000, the Central Board of Direct Taxes said in Circular 789 that Indian tax collectors must honor certificates of tax residency from the Mauritius authorities. The circular was temporarily set aside by the Delhi high court before being reinstated by the Supreme Court in 2003.

The Indian government is moving to replace its existing income tax code with a new "direct" tax code. The proposed new tax code would give the government additional tools to ignore the form of transactions and focus on the substance, for example by declaring transactions as "impermissible avoidance arrangements." This may be used to attack treaty transactions.

In a related case, an income tax appellate tribunal in Mumbai held in March that a service company in Dubai could take advantage of the India-United Arab Emirates tax treaty to avoid withholding taxes on fees that the Dubai service company, Caltex, received from an oil refinery in India.

Caltex could only benefit from the treaty if it was "liable to tax" in Dubai. It did not pay any taxes in fact. The tribunal cited a Canadian court decision for the proposition that actual current taxation is not required; it is enough that Caltex could be taxed in Dubai should the government choose to tax it. The case is *Hindustan Petroleum Corporation, Ltd. v. ACIT.*

BUILD AMERICA BONDS now constitute more than 20% of the municipal bond market, the US Treasury Department said in April.

The bonds are taxable / continued page 9

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the growth of PV capacity in Germany is being raised from 1,700 megawatts to 3,500 megawatts per year. Once the growth of installed PV capacity exceeds 3.500 megawatts, then the feed-in tariffs will be reduced automatically by an additional 2% a year on top of the 9% annual reduction. On top of the scheduled reduction of 9%, tariffs will be reduced at the end of 2011 by another 3% for every 1,000 megawatts of additional growth in PV capacity above the national target. On the other hand, the bill provides that if the market growth in production capacity leaves Germany below a minimum limit of 2,500 megawatts per year, then the feed-in tariffs decrease more slowly. The 9% normal rate of reduction would be shaved by 2.5% for every 500 megawatts that installed capacity is below the minimum limit. ◎

Update: Tax Equity Market

Most renewable energy projects in the United States have been financed in the past largely with tax equity. The US government pays as much as 65% of the capital cost of such projects through tax incentives. Few developers can use the incentives directly, so they barter them in tax equity transactions to raise capital for their projects.

The tax equity market largely collapsed after Lehman went bankrupt in September 2008. Congress reacted by directing the US Treasury in an economic stimulus bill in February 2009 to pay owners of new renewable projects completed in 2009 or 2010, or that start construction in 2009 or 2010, 30% of the project cost in cash in place of part of the tax incentives. The tax equity market started to revive after the Treasury issued rules implementing the 30% cash grant program in July 2009. There were at least 15 active tax equity investors by April 2010, down somewhat from the number before the market collapsed.

The following is an edited transcript of a discussion among six of the largest tax equity investors about the state of the market at an Infocast wind finance summit in late February in San Diego. The panelists are John Eber, managing director of energy investments for JPMorgan Capital Corporation, Jeetu Balchandani, director of private securities, structured leasing and tax investments at MetLife, Jack Cargas, managing director of energy and power finance at Bank of America, Lance Markowitz, senior vice president of the equipment leasing division at Union Bank of California, Marshal Salant, a managing director at Citigroup, and Jerry Smith, a managing director at Credit Suisse. The moderator is Keith Martin with Chadbourne.

MR. MARTIN: What do you see in the year ahead for the tax equity market?

MR. MARKOWITZ: It will be a much stronger year than 2009. We should see a large number of deals. There will be more variety in deal structures. There are more tax equity investors in the market.

MR. BALCHANDANI: The pipeline of deals expected to come to market this year suggests a demand for tax equity that will far outstrip the supply. Anyone looking for tax equity in 2010 should keep in mind there will be limited capacity. Start talking to potential tax equity investors as early in the year as possible.

MR. SALANT: I agree with the point that was just made. Demand for tax equity could easily reach $10 billion a year in 2010 and 2011. If JPMorgan takes $1 billion, we take $1 billion and each other person at this table takes $750 million, you are still $5 billion short, and it is not a simple matter for any of us to close on that volume of transactions this year. The days of casual dating are over in tax equity investing. Tax base is a precious commodity. Investors will want to preserve it for use with their most important relationship clients.

MR. EBER: More deals were done last year in the tax equity market than I think most people realize. We counted 19 wind tax equity deals that reached funding last year for total tax equity of $1.8 billion. That is about half of the tax equity invested in wind in 2008, but it is still a lot more than most people expected given how weak the economy was in 2009.

The most interesting thing about 2009 — and it will continue into 2010 — is that wind developers have options. The US Treasury is paying the cash value of the tax credits on wind farms. Wind companies no longer need to use tax equity, and a lot of companies did not last year. There was a lot of debt raised. Over $5 billion in debt went into wind farms in 2009, more than double the amount of debt the year before.

I agree that tax equity remains scarce. We will see the gap between demand for and supply of tax equity filled with debt.

MR. MARTIN: You said 19 deals last year. How many involved cash grants? How many were legacy deals where tax equity investors committed in 2008 but did not fund until 2009?

MR. EBER: Eight of the 19, or about half, were carryover, almost $1 billion of the $1.8 billion. The majority of the legacy deals — maybe five or six — were deals in which the tax equity investor is claiming production tax credits. We counted seven transactions last year involving Treasury cash grants. Going forward, most deals will involve cash grants.

Mr. MARTIN: Jeetu Balchandani, how many deals will MetLife do in 2010?

MR. BALCHANDANI: Somewhere between eight and 10. In terms of total dollars out the door, somewhere around $500 million in tax equity.

MR. MARTIN: Jack Cargas, is there a way to measure the number of deals that Bank of America will do this year?

MR. CARGAS: There is a way to measure, but I'm not sure I am going to say exactly what that measure is. [Laughter.] We have hundreds of millions of dollars to deploy this year. We will do more than a few transactions, but fewer than too many. [Laughter.]

MR. MARTIN: Lance Markowitz, what about Union Bank?

MR. MARKOWITZ: We will be disappointed if we do fewer than seven or eight transactions this year. Like everyone else, we are constrained not only by a limited tax capacity, but also by internal resources — people.

MR. MARTIN: Jerry Smith, what is the number for Credit Suisse?

MR. SMITH: No exact number. We are looking for the right opportunities. We do not have a cap on how many deals we can do, but there is a natural cap based on internal resources and the quality of transactions that are presented.

MR. MARTIN: I am getting a sense that developers can wait. They do not have to call you next week. There is enough tax capacity in the market that they can wait until March, for example. [Laughter.]

MR. SMITH: Next week would be good though. [Laughter.] We have a hole to fill in the middle of the year.

Merchant Projects?

MR. MARTIN: John Eber, are there parts of the country or types of wind deals that you just will not do? For example, is Texas off limits?

MR. EBER: We have a pretty diversified portfolio. We have done 58 wind deals in 16 states, so we are not worried about geography. However, we are looking for deals with the right characteristics. We are looking for projects with power purchase agreements. We want reliable transmission. There are some parts of the country and specific / continued page 10

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bonds issued by state and local governments to build schools, roads, hospitals and other public facilities. However, unlike the tax-exempt debt that governments usually use to finance such facilities, lenders who buy Build America Bonds pay taxes on the interest they receive, but claim tax credits for 35% of the interest. State and local governments issuing bonds in 2009 or 2010 have the option to receive the value of the tax credits in cash instead of allowing the bondholders to claim credits.

The Treasury said $90 billion in Build America Bonds were issued through March 2010 in 1,066 separate bond issues.

It said that issuers save on interest costs by borrowing with Build America Bonds rather than tax-exempt debt at virtually all maturities. The savings are 31 basis points for a 10-year bond and 112 basis points for a 30-year bond. That's because Build America Bonds appeal to a broader class of investors, including pension funds, foreign investors and insurance companies that have little incentive to purchase tax-exempt debt.

The authority to issue the new bonds expires at the end of 2010. Congress is expected to extend the program, but at a 28% subsidy rate rather than 35%.

UTAH will back out the value of production tax credits, investment credits, Treasury cash grants and state tax credits when assigning a value to wind farms, solar, geothermal and other renewable energy projects for property tax purposes under a new law that takes effect on May 11. The new law should be mean lower property taxes for such projects.

GUARANTEE FEES that a US subsidiary paid to its parent company in Mexico for guaranteeing repayment of debt of the subsidiary did not attract a US withholding tax at the US border, the US Tax Court said.

The IRS is unhappy with the decision and is expected to appeal. / continued page 11

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areas within certain states where there are transmission constraints and projects are at risk of being curtailed.

MR. MARTIN: Will you do offshore wind?

MR. EBER: No one has brought me a deal, so I have not had to answer that question yet.

MR. MARTIN: Marshal Salant, what is the answer from Citigroup to the same questions I just put to John Eber?

MR. SALANT: No one has shown us an offshore wind project yet that was far enough advanced to be able to analyze fully. Geography is not a constraint at this point. Generally, we want projects with PPAs, but we will do projects with hedges where we are providing the hedge or we are comfortable with how the hedge is structured with another hedge counterparty. We are not doing merchant projects. With all the deals to choose from right now, it is hard to convince people it is worth taking the risk.

Start talking to potential tax equity investors as early in 2010 as possible; tax capacity remains in short supply.

MR. MARTIN: Is there anyone on the panel who will do merchant projects or who thinks he will be doing such projects by the end of the year? [Silence.]

MR. MARTIN: I suspect if I were to ask this panel to look at the list of top wind companies, all of you would want to do tax equity deals with the top ten companies and none below that. Is there a way to describe where you draw the line on developers who are too small, too inexperienced, or who have too small a pipeline of potential transactions?

MR. EBER: We have done deals with small developers. When we started in 2003, most developers were small. Many of them were privately owned. To us, it is more a question of the developer having not only the requisite skills to develop and operate, but also having some real capital to put into the project alongside our capital. We want the developer to have significant capital at risk. That's more important than sheer size.

MR. CARGAS: I agree with what John just said. There are several small developers whom we are actively considering because the project metrics look good, the return looks good, and they have significant capital at risk, which makes us more confident they will be as interested as we are in seeing the project succeed. I don't think it is accurate to say we are all focused on just the top 10.

Yields

MR. MARTIN: Jerry Smith, are yields headed up or down in the tax equity market?

JERRY SMITH: Up.

MR. MARTIN: Before we set a pattern that developers won't like, does anyone think that they are headed down? [Laughter.] [Silence.] Does anyone think they will stay where they are currently for a good part of the year?

MR. EBER: I think they will remain stable. The returns we have been getting for the last six to eight months have not varied that much. I don't see that changing in the near term.

MR. MARTIN: John Eber, at the REFF conference in San Francisco last fall, I said tax equity yields were in the 8% to 9% range for the least risky assets — for example, wind farms with proven turbines in places other than Texas. You said yields were at the bottom end of that range. Does that remain true?

MR. EBER: Not much has changed since then.

MR. MARTIN: Those are after-tax yields in unleveraged transactions. Does anyone on the panel disagree with what John just said. [Silence.] At an Infocast conference in late January in New Orleans, Ted Brandt from Marathon Capital argued that tax equity is less expensive in lease structures than partnership flips. He suggested yields in leases could be in the 7% to 8% range. Does anyone want to agree or disagree with Ted?

MR. SMITH: I disagree with him. I see no reason why a tax equity investor would take a lower yield in a lease than he would in a flip partnership.

MR. EBER: The only leasing we have seen getting done currently is in the solar space. It is single investor and the returns we have seen are pretty consistent with the partnership flip returns in the wind space.

MR. MARTIN: Lance Markowitz, what drives the tax equity yields? How closely correlated are they to interest rates, for example?

MR. MARKOWITZ: There is some correlation to interest rates, but tax equity yields are driven more directly by supply and demand. As we were discussing earlier, many traditional tax equity investors did not have much tax appetite last year. That made for a smaller supply of tax equity in relation to demand and drove up yields.

MR. MARTIN: Do the rest of you see it the same way, or is there a stronger correlation with interest rates? Debt competes with tax equity as an alternative way of financing projects.

MR. CARGAS: Interest rates play a role, but it is a loose correlation. The biggest driver for us is how we value our tax balance sheet and how we want to price it. Competing demands on our money from other market segments also has an effect on how much we will want for use of our capital for a wind deal. For example, we have done some pretty significant single-investor leasing of solar projects. We, as well as others on this panel, are involved in the low-income housing tax credit market. That's another place to put capital and yields in that market have been significantly higher on a risk-adjusted basis lately than in wind.

MR. SALANT: I agree there is an indirect correlation to interest rates if for no other reason than banks have a cost of funds for the capital they invest. I see four variables, one being what it costs banks or others to fund their own balance sheets. Another is hurdle rates within different firms. The spread between cost of funds and hurdle rates is wider now than before because we just went through a credit meltdown and people are more risk averse than they were before. Then there is tax capacity. The last factor is yields on competing uses of funds, like other forms of renewable energy and low-income housing.

MR. MARTIN: Let me test what John Eber said about yields remaining steady. I heard no disagreement from any of you about that, but I also heard that you are expecting to be overwhelmed this year by demand for tax */ continued page 12*

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Critics charge the decision will enable foreign multinational corporations with US subsidiaries to "strip" earnings from the United States by having the US subsidiaries pay guarantee fees that escape both US income taxes — because the fees are deductible — and withholding taxes at the border.

The United States collects a 30% withholding tax on outbound payments of interest, dividends, rents and royalties. The rate is sometimes reduced by tax treaties.

The Tax Court said the fees in this case were payments to the Mexican parent company for services. The IRS argued that they were equivalent to interest; they were 1.5% a year of the principal amount of the debt guaranteed. Interest attracts a withholding tax. Payments for services do not because the income is considered earned in the place where the services are performed — in this case Mexico. US withholding taxes are collected only on income considered earned in the United States. Interest has its source where the borrower paying the interest resides.

The case is *Container Corporation v. Commissioner*.

PRODUCTION TAX CREDITS for generating electricity from wind, geothermal and closed-loop biomass projects are 2.2¢ a kilowatt hour in 2010, the IRS said in April.

They had been 2.1¢ in 2009. The credits can be claimed on the electricity output from a project for 10 years after the project is originally placed in service.

Production tax credits for open-loop biomass, landfill gas, ocean energy and waste-to-energy projects will remain at 1.1¢ a kWh in 2010, the same rate as in 2009.

The tax credits are adjusted each year for inflation.

The credits will start to phase out if the average price at which electricity is sold under wholesale power contracts reaches 11.47¢ a kWh. The IRS said the average */ continued page 13*

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equity. I also heard that the cost of funds will be a factor, and I have been reading in the paper about Greece, and possibly Spain and Portugal, having economic trouble, with the result that credit default rates are going up. Is there a disconnect? Can yields remain steady if you have such pressure on the demand side and the cost of funds?

MR. EBER: The reason I say that yields will remain steady is that, for years in this business, we were really fortunate that people had to use tax equity and, as I mentioned before, today, most companies don't appear to have to use tax equity. It is a nice option. It gets more value for tax subsidies than the subsidies are worth if the developer retains them and carries them forward. However, there is a cap on how high tax equity yields can go above which developers will just borrow money, forgo immediate use of the tax subsidies and use them later in the life cycle of the wind project.

MR. MARTIN: That is how tax equity yields are tied to interest rates.

MR. EBER: Yes. There is an equilibrium imposed by the competition with debt financing, and that is a new phenomenon. The fact that the developer can trade the tax credits on his project for a cash grant from the US Treasury changed the dynamics of the tax equity market.

MR. MARTIN: Let me throw this question out like a jump ball. What percentage of wind deals in the tax equity market this year will involve production tax credits versus Treasury cash grants?

MR. EBER: Ten or 15%.

MR. MARTIN: That's small. Anybody disagree?

MR. SALANT: All the deals we are looking at now involve cash grants. If you are talking about future deals, maybe one out of 10 will involve production tax credits.

Debt Premium

MR. MARTIN: Jeetu Balchandani, how much of a premium does a tax equity investor charge for use of his money if there is leverage at the project level in a partnership flip transaction?

MR. BALCHANDANI: We think current yields in leveraged flip deals are between 13% and 15%.

MR. MARTIN: Whoa. If you are at 8% or 9% without leverage, that is a huge premium.

MR. BALCHANDANI: Yes.

MR. MARTIN: Does anyone have a different view of the premium?

MR. SALANT: Leveraged yields have bounced all over the place. Most of the deals that Citi is looking at today are leveraged transactions; some even include DOE guarantees on top of the debt. The spreads are definitely wide. We have not seen any leveraged yields get anywhere close to 10%. I would say 12% is a good number. I would not expect to have to go to 13% to 15%, but it depends on the deal.

MR. MARTIN: John Eber, you and I have been on a lot of panel discussions together. In the past, people have always said the yield premium for project-level debt was 250 to 300 basis points. How does that square with what you just heard?

MR. EBER: They were talking about the yield premium on the old production tax credit flip deals that were leveraged and, on those deals, the average life of a tax equity investment was much longer, so you could get a couple hundred more basis points and be adequately compensated on a risk-reward basis. If you look at the deals with the Treasury cash grant, the tax equity gets paid back incredibly fast, so this high return you just heard about is a little deceptive because the tax equity investor is earning it over a very short period of time. His book earnings and the nature of the investment are significantly different than in the old PTC deals; therefore, the yields that investors have been looking for in cash grant transactions will look different.

> There were 19 tax equity deals in the wind market in 2009. Seven involved Treasury cash grants. Most of the rest were legacy deals carried over from 2008.

MR. MARTIN: Isn't there something inconsistent with saying the investor needs a much higher yield than before if there is leverage, but he is getting paid back more quickly so that he is not exposed to the debt for as long a period of time as before?

MR. EBER: There is a faster payback, but leverage creates long-term issues. The investor's yield tends to go backwards as the debt is being repaid because cash goes to repay debt, but the investor still has to report the electricity revenue as taxable income. It could take you 15 or 16 years before you finally get out of that position.

Cash Grant Issues

MR. MARTIN: Has any of you run into issues with the Treasury cash grants or is the program just working fine?

MR. CARGAS: We have run into a few issues where payment of grants was delayed while the developer responded to questions from the Treasury. We have been hearing in the solar residential sector that there may be a cap on how large a grant the Treasury is willing to pay per watt of installed capacity.

MR. EBER: We have done wind deals with Treasury cash grants. Everything has gone smoothly. The grants were paid quickly. We have been pleasantly surprised at how well the program has worked.

MR. SALANT: We were also pleasantly surprised on the AES deal that we did. The Treasury delivered the money right away. Everything went incredibly smoothly.

MR. MARTIN: If there are no other issues with the current program, has any of you had time to look at the bill that was introduced in the House last week to extend the cash grant program, but make the grants look more like tax refunds. If so, do you have a view whether that works?

MR. EBER: Economically, it seems to be the same as what we have currently with the grant. My sense is it was just a way to move the whole program more under the IRS and get it out from under DOE and NREL, but it looks to me like a nice substitute. The real beauty of it is you are talking about a two-year extension of a cash-type program. The industry would prefer to extend the existing grant for two another years without any changes, but that doesn't seem to be on the table at the moment, so it looks good to me to get two more years of a similar kind of program.

MR. CARGAS: My reaction is why not leave well enough alone? Congress seems to going out of its way to emphasize that the refundable tax credit would work / continued page 14

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price for contracted electricity from wind is currently 4.22¢ a kWh. It did not try to calculate the prices for electricity from other renewables.

Developers have the option on renewable energy projects placed in service in 2010 or that start construction in 2010 to forego tax credits and receive a payment from the US Treasury for 30% of the project cost.

The IRS said tax credits for producing refined coal will be $6.27 a ton in 2010. "Refined coal" is coal that is less polluting than raw coal. It said the credits will start to phase out if raw coal prices reach 1.7 times the raw coal price in 2002, which, adjusted for inflation, was $45.75, so the phase out would not start until raw coal prices reach $77.77 a ton. The IRS said the 2010 reference price for raw coal is $54.74 a ton.

R&D TAX CREDITS are hard to claim because the IRS defines research narrowly, but a federal court decision involving a ship builder sheds light that may help companies in the energy sector.

Trinity Industries built six "first in class" boats for various customers that had to be specially designed for the particular uses to which the customers planned to put the boats. The company hoped it might eventually have orders for more, but there was no guarantee.

For example, one of the boats was a "Mark V" high-speed craft that the company designed for use by special forces units. The craft had to fit in a C-5 cargo plane for rapid deployment. It had to move at unusually high speeds, have a low surface area and throw off little engine exhaust to avoid detection by radar and infrared sensors. It also had to be able to carry a variety of weapons. Another boat was a double-hulled oil barge that was a response to the Exxon-Valdez oil spill.

The IRS defines "research" as a process of experimentation undertaken to discover information that is technological in nature and that will be used to develop new or improved components for the taxpayer's products.

The IRS argued that / continued page 15

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just like the existing cash grant. Well, in order to do that, one must codify a lot of law. Why not simply change a date and extend the existing program?

MR. MARTIN: There is a feeling in the House that if the date were merely changed, then the spending committees would have to get involved. It would require a new appropriation. The mood has turned dark in Washington on additional spending. The public is concerned about large budget deficits. The House tax committee wants to find a way to extend the program without having to get a new appropriation.

MR. SMITH: The biggest issue I see is there has been a trend to bridge the cash grant either with debt or tax equity. It is easy to get a tax equity investor to bridge the grant when it is a 60-day exposure. Changing to a tax refund program elongates the exposure. There is more uncertainty about when the refund will be paid.

MR. SALANT: It really is a shame. This is a classic story of Washington politics. We are taking a program that everyone believes works well and making it so much more complicated because we are trying to avoid having to pass it through multiple committees in Congress.

MR. EBER: There is also some irony because the industry asked last year for a refundable tax credit. Everyone likes the cash grant program that Congress gave us instead. Now the House is proposing to go back to what we originally requested. It puts the industry in an awkward position to turn it down and ask for something else when that something else is not even on the table.

MR. MARTIN: Let me take a flash poll of the audience. How many people are concerned that the federal budget deficit it too high? [Laughter and show of hands.] How many of you think the government ought to cut spending as the principal way to address this problem? [More laughter and show of hands.] How many think the government should increase taxes? [Few hands.] How many think the government, despite cutting spending to address the deficits, should spend more on extending cash grants for wind? [Many voices and laughter.]

That's the political problem, and that's why the House tax committee is trying to find a way to turn the cash grants into a tax program that does not — at least on its face — require more spending.

Tax equity yields are expected to remain stable.

What happens next year if Congress does not extend the cash grant program and you are faced with a few projects that are grandfathered for cash grants and a host of other projects that qualify only for production tax credits? Do you have such a strong preference for cash grants that it will be hard for developers to do PTC deals in 2011?

MR. EBER: We will do either. We are doing PTC deals today and we will remain happy to do them, but I think the industry will be in tough shape if Congress fails to extend the program because there is still not enough tax capacity to handle all the tax credits that would hit the market.

MR. CARGAS: We have a fairly strong preference for unleveraged cash grant partnership flip deals. We will look at all structures, but that is our preference this year and it will probably continue into next year.

MR. BALCHANDANI: We also have a preference for cash grant deals. Even if the cash grant program were to lapse and we could use tax credits, the accounting treatment for investment credits is better than for production tax credits and neither is as favorable as the treatment in a cash grant deal.

MR. SALANT: I think all of us probably have the same view. Certainly at Citi, we would say whatever Congress dishes out, we will figure out how to deal with it. We will make it work. It is the developers who would get hurt, because the cash grants give them the option of skipping tax equity and financing with debt.

MR. MARTIN: Jeetu Balchandani, a reporter for Power Finance & Risk asked yesterday about the accounting treatment for cash grant deals. Is it worse when you move to a cash grant than it was for PTCs, she asked, and is that making it harder for developers to raise tax equity? You suggested no. In fact, the accounting treatment is better with cash grants. Why?

MR. BALCHANDANI: We account for PTC deals on a pre-tax book basis. There are negative earnings. When we look at grant transactions, we use grant accounting and that allows positive pre-tax book income.

MR. MARTIN: Let's move to a lightning round of questions. I am looking for quick answers. Feel free to add to what someone else has said.

Most wind developers are claiming either Treasury cash grants or production tax credits on their projects, but they have the option to claim a 30% investment tax credit and that option will remain available through 2012 during a period when it may no longer be possible to claim Treasury cash grants on some projects. Jerry Smith, does the partnership flip structure work as well for projects on which investment credits are claimed as it does for projects claiming production tax credits or Treasury cash grants?

MR. SMITH: Yes, I think it does.

MR. MARTIN: Is it helpful or unhelpful that a developer plans to make a depreciation bonus part of the tax structure?

MR. EBER: It is helpful. The bonus is an additional benefit.

MR. BALCHANDANI: It is not a plus for everyone. I think the answer depends on your tax capacity. Adding a bonus makes the claim on tax capacity lumpy at the outset. It helps the developer to say the depreciation on a project is more rapid, but the additional time value may go unused by the investor.

MR. MARTIN: It might knock an investor out of the market earlier in the year, and the investor would rather spread his capacity over more deals?

MR. BALCHANDANI: I think that's right.

Capital Stack

MR. MARTIN: What share of the capital cost of a project can a wind developer raise in a partnership flip structure? Is it 20%, 50%, less, more?

MR. EBER: As much as 65% to 70%.

MR. MARTIN: How common is it for a developer to be able to raise 65% to 70%?

MR. EBER: It is not uncommon. It is a function of how much cash the project generates and the amount / continued page 16

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Trinity did little more than allow customers to order off a menu: "pick a hull design from column A, a propulsion system from column B."

The court disagreed. It said the process used by Trinity varied from all-new hull designs to cafeteria-style mix and match combinations of existing elements to slight modifications of existing designs. It said it would allow R&D tax credits to be claimed on the entire cost of a boat if 80% or more of the effort that went into building the boat involved a process of experimentation, measured on a cost or other consistently-applied reasonable basis. If Trinity could not reach the 80% threshold for the entire boat, then it should identify the largest subset of components that satisfies the test. The court said this "shrinking back" rule only comes into play if the company cannot reach 80% on the entire boat.

The US tax code allows companies to claim a 20% tax credit for their spending on research. The credit is claimed only on incremental research during the year, meaning the amount a company increases its research spending above a base. However, companies have the option of using a sliding formula instead and taking a smaller credit based on research spending as a percentage of average gross receipts over the last four years. For example, the credit would be 3% of research spending above 1% of gross receipts, 4% of such spending above 1.5% of gross receipts and 5% of research spending above 2% of gross receipts.

The tax credit expired at the end of 2009. Both the House and Senate voted to extend it through 2010 as part of a tax extenders bill that is expected to clear Congress by late May.

SMART GRID GRANTS do not have to be reported as income if received by a corporation, the IRS said in March.

The grants are matching grants paid by the US Department of Energy to utilities to cover 20% to 50% of the cost of meters, computer software, sensors and / continued page 17

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of the Treasury cash grant. The grant is 30% of the project cost. The tax equity will fund it but get the money back when the grant is paid. His remaining contribution may be as much as 40%. In a project with production tax credits, the number will be a little less. Then the developer turns around and arranges back leverage to raise the remaining capital.

MR. MARTIN: Jerry Smith, you did some partnership flip transactions last year on projects with Treasury cash grants. What share of project cost was the developer able to raise in tax equity?

MR. SMITH: It was around 20%. It depends on whether the tax equity investor bridges the grant or whether there is a lender at the project level who bridges the grant. If the tax equity bridges, you are looking at a total tax equity investment of something like 47% of the project cost.

MR. MARTIN: Lance Markowitz, what was your experience last year?

MR. MARKOWITZ: The developer raises about a third of the project cost if you exclude the Treasury cash grant.

MR. MARTIN: So the developer raises about 63% of the project cost if the tax equity bridges the cash grant. Does anyone else on the panel want to offer a different figure?

MR. EBER: You have to be careful with these numbers, Keith. In a grant world, you can structure the transaction so that the flip is expected to occur anywhere from year seven through 10. The more distant the flip, the more tax equity the developer will be able to raise. Another factor is whether there will be debt at the project level. What you heard from Jerry Smith may be for a leveraged deal where there is debt being used in place of tax equity.

MR. MARTIN: How do the two factors — leverage and when the flip is expected to occur — affect how much tax equity can be raised?

MR. EBER: Debt at the project level reduces the amount of tax equity that can be raised. The tax equity investor will want a higher yield to compensate for the risk that it will be squeezed out after a debt default before it reaches its target yield. There will also be less cash for the tax equity investor because cash will go first to pay debt service. A cash-poor benefits stream to the tax equity investor discounted back at a higher target yield means a lower number.

The length of time before the flip is expected to occur cuts in the other direction. The longer that period, the more the tax equity investor will invest because he will get a larger share of his return in cash.

Tax equity in partnership flip deals in the wind market covers about 20% to 33% of the project cost net of the Treasury cash grant.

MR. SALANT: On a leveraged deal, if you add up the various tiers of the capital structure, you have a Treasury cash grant, project-level debt and tax equity, but there is still an amount that the sponsor has to contribute in pure equity. In the leveraged deals that we see, the sponsor equity would be as low as 15%, but 20% is more common. There have been some deals as high as 30% and perhaps one or two as low as 10%.

MR. MARTIN: We did a deal with you where the sponsor equity was 13%. I was going to get there. What percentage of the capital structure should be developer expect to have to put in as sponsor equity?

MR. EBER: Somewhere around 15% to 20% by the time you get down to it. The sponsor may be able to raise its equity by borrowing back-levered debt at the sponsor level.

MR. MARTIN: Will you do a partnership flip deal with project-level debt?

MR. CARGAS: We will look at it, but we have a strong preference for unleveraged cash grant partnerships.

MR. BALCHANDANI: Yes, we will. Most of the transactions at which we are looking at currently are leveraged partnership flips.

MR. MARKOWITZ: Yes.

MR. SMITH: Same.

MR. EBER: Yes.

MR. SALANT: We actually prefer leverage, so we are at the other end of the spectrum from most tax equity investors.

MR. MARTIN: Why do you prefer leverage? Citibank provides the debt?

MR. SALANT: Maybe. More often the lender is another bank. We are seeing two problems currently. One is the developers are looking to minimize what they actually have to put in as equity. The other issue is the emergence of super large deals that we did not see in the past. We have been looking at three deals that are in the one and a half to two billion dollar range. There is not enough tax equity to do a two billion dollar deal with just sponsor equity and tax equity. The only way deals that size work is with leverage.

DOE Loan Guarantees

MR. MARTIN: Will you do a partnership flip deal with leverage if the lender is the Federal Financing Bank or a private lender backed by a DOE loan guarantee?

MR. MARKOWITZ: It is less attractive.

MR. MARTIN: Why?

MR. MARKOWITZ: We do not see a lot of deals closing to begin with and adding the Department of Energy to the mix creates additional friction. The concept of having to negotiate with the US government if the deal runs into difficulty and goes into workout mode is a little daunting.

MR. MARTIN: I think you mentioned to me at one point, Lance, that your phones have been ringing off the hook with people seeking tax equity. Is the issue why spend your scarce time on a deal that may be harder to close?

MR. MARKOWITZ: That's the other point. If you are restrained from a resource standpoint, and one deal has a clear path to closing and the other one does not, which one will you take, other things being equal?

MR. MARTIN: Has anyone had to deal yet with DOE on working out the tax equity-versus-debt issues?

MR. SALANT: Yes. I guess we are gluttons for punishment because we have two live ones. One has a section 1703 loan guarantee, so the lender is the Federal Financing Bank. Lance is right. I would be lying if I said it was easy, but we are working through everything, and the DOE team in Washington seems to want to do the right thing. The other transaction is expected to involve a section 1705 loan guarantee / continued page 18

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control devices that help manage the electricity grid.

The IRS said that it views the grants as a capital contribution by someone who is not a shareholder when the recipient is a corporation. Capital contributions do not have to be reported as income.

The agency made the announcement in early March in Revenue Procedure 2010-20.

Power companies may have been hoping for another theory for not taxing the grants; the theory the IRS used suggests the grants may have to be reported as income if received by a partnership.

Meanwhile, the Maryland attorney general said shortly before the IRS announcement in an opinion in late February that the grants are income to utilities in Maryland. Maryland starts with a federal definition of taxable income and makes adjustments. He reasoned that since the grants are taxable at the federal level, they must also be taxable in Maryland. The opinion was rendered moot by the IRS decision two weeks later.

A VALUATION by the IRS showed no meaningful effort by the government to arrive at a proper value, a court said.

It denied the government's claim for more taxes.

Duchossois Industries was building a factory in Mexico to make garage door openers in the 1980's when oil prices collapsed and left Mexico struggling to service its foreign debts. The government came up with a creative program where companies like Duchossois that needed Mexican pesos to pay local workers could buy Mexican government debt from foreign holders and then swap the debt with the government in exchange for pesos paid into restricted accounts.

Duchossois purchased Mexican debt with a face amount of $11.7 million from the First National Bank of Chicago for $5.8 million. The Mexican government then / continued page 19

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through the FIPP program. It is a very large deal and we are spending hundreds, if not thousands, of hours working through 120-page term sheets. Keith, you are aware of the transaction. The documentation may ultimately be a thousand pages. It is not fun, but we are working through it and, hopefully, the next time around it will be quite this difficult.

MR. MARTIN: Does a partnership flip deal work if the construction lender bridges the cash grant so that the cash grant goes to pay down debt and all the tax equity investor is left with is depreciation?

MR. SMITH: Yes, it does. We just closed a deal where that was the case.

The longer the period to the flip, the more the tax equity investor will pay for an interest in a project.

MR. MARTIN: You receive the same cash? It just comes later in time? The Treasury cash grant paid down the debt so that the debt does not require as much cash to pay debt service over time?

MR. SMITH: Absolutely right. I should say one thing. Although most of the market prices things on an after-tax basis, we think of the world as a pre-tax world. We tell developers your debt costs this much, and the tax equity is providing a mezzanine level of capital. You should think about how expensive it is, but not really worry about what we get from it. Whether our tax capacity is there to provide a benefit or not, it costs X. Returning to your original question of whether it works if someone else gets the cash grant, it does. The benefit we see is not so much the timing benefit of the depreciation but the permanent tax basis step up.

MR. MARTIN: Permanent tax basis step up? Explain that.

MR. SMITH: Most people think of the grant as causing a basis step down. In other words, for accounting purposes, the project company gets the cash grant in and that reduces the carrying value of the company's assets for book purposes by the amount of the grant. However, what happens from a tax perspective is that the basis does not drop by the full 30%. It drops by only 15%. The analogous impact on the tax equity investor is that the basis of its interest in the company is stepped up by 15% for tax purposes compared to where it is for book purposes.

Leveraged Leasing

MR. MARTIN: Next question. Will you do a lease of a wind farm?

MR. MARKOWITZ: I think it works. It may be appropriate for some projects.

MR. MARTIN: What tells you whether it works for a particular project?

MR. MARKOWITZ: The key is what the developer wants. Many developers tell us all they really want is to monetize tax benefits, so they probably do not want us hanging around for very long, which is what happens in a lease. Other developers are looking for more of a long-term financing arrangement with more leverage and, in that instance, a lease makes more sense.

MR. MARTIN: Are the rest of you open to a lease for a wind farm or do you think it is just not a good structure for wind?

MR. EBER: You talking a leveraged lease?

MR. MARTIN: Let me start with single-investor lease where the tax equity funds 100% of the project cost and then work to a leveraged lease where the tax equity puts up perhaps 13% to 20% of the capital and the rest is debt.

MR. EBER: A single-investor lease is not a practical solution. There is just not enough tax equity available in the market. Even with leveraged leases, the number of investors willing to invest into such structures is falling. Most of the leasing activity is in the rooftop solar sector and it tends to be single-investor deals. The revenue stream that the lessee uses to pay rent is more predictable in solar than in a wind farm.

MR. CARGAS: We have done a lot of single-investor leasing in distributed generation and commercial-scale solar, and we do not rule out doing that kind of transaction in wind. That would be particularly true if the lessee is a well-heeled credit-worthy developer who is willing to put his own credit on the table.

MR. EBER: That was interesting what Jack just said. He is talking about a credit-based lease. Everything we have been discussing until now is project financing. Leasing is tough to make work where the lessor must look solely to the project to cover the rents under the lease.

MR. MARTIN: Which I think means that lessors require a fairly sizable cash reserve to backstop rents — maybe six months, longer? — which may make the lease less attractive to the developer. Does such a reserve get you over the credit issue?

MR. EBER: The only thing that gets over the credit issue is that a large investment-grade developer is the lessee and he is fully obligated for all the lease payments over the life of the lease.

MR. MARTIN: Let's set the credit issue to one side for a moment. You said you are skeptical whether single-investor leases work because there is not enough tax equity to cover 100% of the capital cost of these projects. What about leveraged leases?

MR. EBER: You get into the issue of whether you want to tie up your equity for 15 or 20 years in a lease. It is a big lift.

We have been doing wind deals since 2003 — a total of 58 transactions to date. I have seen the cash flow on these projects and, trust me, it is not terribly predictable. When people talk about it being intermittent, it is intermittent from zero some months to 150 other months. It is not easy to figure out how it will look over the life of a lease. The lessor wants a steady monthly payment.

MR. MARTIN: Any other views on leasing and its suitability for wind?

MR. BALCHANDANI: I agree with Lance that it makes sense only for a minority of projects. It may be more attractive for investors like insurance companies that want to invest money long term.

MR. SALANT: We will consider it at Citi, but we are more likely to go with partnership flips for wind. We see leasing as more applicable for solar.

Audience Questions

MR. MARTIN: Let me take a couple questions from the audience. / continued page 20

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paid Duchossois $10.2 million worth of pesos to cancel the debt.

The IRS said the company had to report the difference of $4.4 million between what Duchossois paid and what it received in pesos as taxable income.

There were significant restrictions on how the pesos could be used. For example, they could only be used to pay Mexican vendors and contractors working on building the factory. The IRS claim that the company had $4.4 million in income failed to treat the pesos as worth less on account of these restrictions.

The court said it would place an unreasonable burden on taxpayers to let the government assign an arbitrary value and force taxpayers to prove property was worth less. "When the government provides nothing more than a 'naked assessment,' which is to say 'without any foundation whatsoever,' the taxpayer does not have to prove what the assessment should have been," the court said quoting from an appeals court decision in another Mexican debt swap case.

The case is Duchossois Industries, Inc. v. United States. *A federal district court in Illinois released its decision in the case in mid-April.*

A US AIRLINE had to withhold taxes on wages paid to foreign flight attendants who staffed flights between the United States and other countries, the IRS said in a long technical advice memorandum that the agency released in mid-April.

A technical advice memorandum is a ruling by the IRS national office in a dispute between a company and an IRS agent on audit.

All of the flight attendants in question are based abroad and are paid in local currencies. The IRS said the airline had to apportion part of their wages each year to the United States based on the total hours that each works inside and outside the United States and withhold US taxes on the share of wages / continued page 21

Tax Equity

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MR. STORCH: Mike Storch, Enel North America. We are finding more utilities want an option to purchase the project in the power purchase agreement. Some utilities are fairly aggressive and want an option to buy the project after 10, seven or even five years. What is your reaction to such options? Do they kill your interest in the project or are you fine with such options provided the utility must wait to purchase until after at least X years?

MR. EBER: Great question, Mike. We actually have a product on which we are working to layer in a buyout for utilities. If a utility can buy electricity from a project for five, six, seven years and the tax benefits flow through to the utility in the PPA pricing and then the utility can buy out the project under more favorable financing terms, it can be a real winner for ratepayers. The question is how many developers want to play in that market.

MR. SMITH: I agree with what John said. Be careful, though, that it is not a reasonable certainty that the utility will exercise the option or the utility may be treated as owning the project for tax purposes from day one.

MR. MARTIN: Other questions from the audience?

MR. METELO: Joao Metelo, Horizon Wind Energy. The question is about yields. We have not seen a large difference in the past between yields in cash grant flip deals and PTC deals. It is obvious that cash grant flip deals present much less risk to investors and a much faster payback period. Do you expect that the yields between PTC and cash grant flip deals will widen so that cash grant flip deals are more competitively priced?

MR. CARGAS: That's a good question. You may start to see a divergence in yields if the cash grant program is extended. ◎

Swap Gets Wholesale Generator Into Trouble

by David Evans and Karen Zachary, in Washington

KeySpan Corporation, an electric and gas utility in New York, agreed to pay the federal government $12 million in damages in February 2010 for entering into a swap that the government charged kept electricity prices high in New York City.

KeySpan made the payment to settle a civil antitrust suit brought by the US Department of Justice. The government claimed that KeySpan's conduct violated a section of the "Sherman Act" that prohibits conduct that unreasonably restrains interstate commerce.

The Federal Energy Regulatory Commission declined in 2008 to take action against the utility after the FERC staff concluded that the swap did not contravene the tariff the utility had on file with FERC and did not violate FERC regulations aimed at preventing manipulation of the wholesale power market.

Bid the Cap

From May 2003 to March 2008, KeySpan was one of three pivotal suppliers of electricity in the New York City area. The electricity grid in New York is managed by an "independent system operator" called the NYISO. The NYISO requires retail providers of electricity to New York City customers to purchase 80% of their capacity from generators in that region. Prices are set through auctions by having the suppliers offer price and quantity bids, subject to certain caps.

Virtually the entire generating capacity in the region was fully dispatched during the period from June 2003 to the end of 2005 to meet local demand, which meant that KeySpan could sell almost all of its capacity at the top price. The company owned a 2,400-megawatt power plant in Queens called Ravenswood.

New generating capacity was expected come on line in 2006. As a result, KeySpan could no longer be confident that its bid-the-cap strategy would remain profitable after 2005.

The Department of Justice charged that KeySpan considered three responses to these changed market conditions.

First, the utility could withhold capacity from the market to keep prices high, but this would reduce its revenues by an estimated $90 million a year.

Second, it could compete by bidding more capacity at lower prices, which might produce higher returns than bidding the cap but also might result in losses if the competition undercut its bids and took away sales.

Third, KeySpan could acquire one of two other power plants that were also bidding to supply electricity to the grid from Queens. One of the plants, owned by Astoria Generating Company, was 1,800 megawatts.

Owning the Astoria facility would have given KeySpan enough capacity to make continuing to bid the cap its best strategy. KeySpan decided not to pursue the purchase directly after concluding that acquiring its largest local wholesale competitor would raise market power issues and could be challenged by regulatory agencies. However, it acquired an indirect financial interest in the capacity from the Astoria plant by entering into a derivative transaction with Morgan Stanley Capital Group Inc.

Swap

Under this so-called "KeySpan swap," if the market price for capacity was above $7.57 per kw-month, then Morgan Stanley would pay KeySpan the difference between the market price and $7.57 times 1,800 megawatts. If the market price was below $7.57, then KeySpan would pay Morgan Stanley.

KeySpan understood that Morgan Stanley would need to enter into an agreement with another wholesale supplier in order to offset its payments to KeySpan and that Astoria was the only supplier with enough capacity. Morgan Stanley entered into a hedge agreement with Astoria where if the market price for capacity was above $7.07 per kw-month, then Astoria would pay the difference times 1,800 megawatts; if the price was below $7.07, then Morgan Stanley would pay Astoria the difference times 1,800 megawatts.

The Department of Justice charged that, via Morgan Stanley, "KeySpan would pay Astoria a fixed revenue stream in return for the revenues generated from Astoria's capacity sales in the auctions." It said the competitive effect was the same as if KeySpan had purchased the output from the Astoria plant directly and kept it off the market.

Once the swap went into effect, KeySpan consistently bid the cap, even though a large portion of its capacity was going unsold. During this period, significant additional generating capacity in New York City was brought on line, but the market price for electricity did not decline.

The swap deal ended in March 2008 when the NYISO forced KeySpan to sell the Ravenswood generating plant as a condition for approving the takeover of KeySpan by National Grid plc. National Grid cooperated with the federal investigation and no longer owns the Ravenswood plant. Since the swap deal ended, the market price for capacity in the NYISO auctions has declined.

The case is the first in which the Department of Justice sought the legal remedy of "disgorgement" in a civil antitrust action. Typically, the government would ask only for an injunction to prevent future antitrust violations, */ continued page 22*

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apportioned to the United States. However, withholding is not required if a flight attendant is physically present in the United States in fewer than 90 days during the year and less than $3,000 in wages are apportioned to the United States.

The ruling goes into great detail about when so-called FICA and FUTA taxes — for Social Security, Medicare and unemployment benefits — must also be paid. It is Technical Advice Memorandum 201014051.

MINOR MEMOS. There is a growing sense among economists — but not yet politicians — that European-style value-added taxes are inevitable in the United States to deal with the enormous federal budget deficits. The Congressional Budget Office is studying how different forms of value-added taxes work, Douglas Elmendorf, the CBO director, said on April 8. One week later, the Senate went on record in a 85-13 vote as opposing such a tax. The chairmen of both tax-writing committees in the House and Senate said emphatically that a VAT is not on the table. Meanwhile, a bipartisan deficit reduction commission appointed by President Obama will have to find as much as $500 billion in tax increases and spending cuts over the next few years if it is to reach its goal of wrestling the federal deficit to 3% of gross domestic product by 2015 . . . . Two IRS officials warned the audience at the National Historic Tax Credit Conference in March that the agency is finding problems with complicated partnership transactions to transfer tax credits for renovating historic buildings. Colleen Gallagher, an IRS examiner, said the agency is seeing more and more complicated deal structures, use of "lease stacking" to circumvent restrictions on leasing equipment to tax-exempt entities and other issues.

— contributed by Keith Martin and John Modzelewski in Washington.

Swaps

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but given the facts of the case, that remedy would have been meaningless. KeySpan no longer owns the plant and without the disgorgement remedy, KeySpan would retain the benefits of its anticompetitive conduct.

Caution

Does the case suggest that there are potential antitrust implications any time a wholesale generator enters into an electricity hedge or swap? Probably not, given that this swap involved a unique market, produced no counterbalancing efficiencies and clearly affected prices.

Nevertheless, generators entering into swaps should be cautious if the swap involves a competing company in the same market.

There is no indication that the Department of Justice is targeting the heavily-regulated electricity generating sector, but it is notable that Justice brought this case even after FERC declined to take any action. This could signal an increased interest by the antitrust team in tackling anticompetitive conduct within regulated industries.

Finally, a crucial factor may have been the suggestion that KeySpan was attempting to avoid the antitrust questions that inevitably would have arisen had it attempted to acquire the Astoria facility. ◎

Tax Credits for Green Manufacturers: Who Will Use Them and How

by Eli Katz in New York, and John Marciano in Washington

The challenges are only just beginning for companies that were awarded $2.3 billion in tax credits in January as an inducement to build new factories to supply components for the "green" economy.

They must now move quickly to line up financing structures that will enable them to use the tax credits they were just awarded.

This will not be easy or cheap.

The tax equity market still has far more sellers than buyers, and conventional tax equity investors may be reluctant to finance manufacturing equipment with highly uncertain profit projections.

What Challenges?

Most tax credit deals have historically been done on fully-contracted assets where technology and asset performance risk were relatively low. Tax equity investors will now be asked to finance a new asset class: factory equipment with short-term or no customer supply contracts that are far more variable in pricing and terms than is typical in conventional project financing.

Nonetheless, companies with strong balance sheets should be able to attract tax equity investors into lease financing or other tax credit monetization structures if they can find ways to manage the key risks inherent in owning and operating manufacturing equipment.

The tax credits are found in section 48C of the US tax code. The owner of a new factory that makes wind turbine blades, solar modules, fuel cells or similar equipment can claim a credit against its federal income taxes for 30% of the capital cost. The credit is taken when the new factory is placed in service. Congress authorized $2.3 billion in such credits nationwide in an economic stimulus bill in 2009. The Internal Revenue Service made awards in January to companies who applied for them. The companies who received awards promised to build 183 new factories.

The awardees generally fall into three categories. The first are US multinational corporations with large projected tax liabilities. These companies may well decide to use the tax credits themselves to offset taxes that they would otherwise owe the government. A second subset of tax credit awardees are small companies, with little or no current or projected tax liability. This group will be looking to trade its tax credits for upfront equity but will likely struggle to do so because it will have to attract tax equity investors into complex financing structures where they have limited ability to protect against some key risks that these investors may be unwilling to bear. The tax equity market is likely to coalesce around the third group of tax credit awardees: those that have deep financial backing through private equity funds or foreign-based parent companies that have little or no use for the tax credits but are willing and able to use their balance sheets to wrap risks that are obstacles to raising tax equity.

Key Rules

The tax credit has many of the same features now familiar to developers and investors in projects that generate renewable power. The tax credit can be claimed by anyone who received an allocation of tax credits from the government and who owns or leases manufacturing facilities that will make components for a wide range of green projects. The credit is claimed on the cost of equipment for the factory, but not any building. It vests ratably (20% per year) over five years. The unvested portion of the credit must be returned to the government if the property is disposed of any time during the first five years after the factory starts operating. The credit may also be partially disallowed if tax-exempt entities lease the manufacturing equipment or take a stake in the manufacturing equipment or the entity that owns it.

When the owner of the manufacturing equipment claims the credit, it must reduce its tax basis in the equipment by the full amount of the credit. This leaves less basis to depreciate in the future. A key exception to this rule is when the credit is claimed by someone who merely leases the equipment rather than owns it. In this case, the owner (the lessor) is not required to reduce its tax basis because it is not claiming the tax credit; instead the lessee must pay tax on a stream of hypothetical income equal to the credit. The income is claimed over the depreciable life of the equipment. For example, if the equipment has a 7-year depreciable life, and the tax credit is $1 million, then the lessee must report $1 million of income ratably over seven years.

Credit awardees must have executed an agreement with the IRS by March 15, 2010. Once the IRS countersigns and returns the agreement, the awardee has just one year to follow up with a certification showing that it has obtained all the key permits to move forward with the project. It then has three years to commission the factory or risk losing its tax credit allocations. In a recent notice, the IRS cautioned that it reserves the right to disallow tax credits if the applicant changes its plans in a significant way. Nonetheless, the IRS has indicated informally that it will not consider investment by a tax equity investor as a significant change in plans, although it will ask any new investor to sign off on the terms of the program.

Tax Credit and its Discontents

The government's decision to give out tax credits to incentivize the building of the clean-tech supply chain was somewhat surprising in that it reverses a trend that saw green energy subsidies moving away from tax-based subsidies to cash-based subsidies. A recent example is the wildly successful Treasury cash grant program that temporarily replaced the investment and production tax credits as a means to subsidize renewable energy power projects. At last count, the Treasury had already given away nearly $3 billion in cash grants to hundreds of power projects built in the US.

"Green" manufacturers who were awarded $2.3 billion in tax credits by the IRS in January may have a hard time converting them into current cash.

A tax credit is a right to offset a tax that is otherwise owed to the government. A tax credit is almost always more valuable than a tax deduction because a tax credit reduces the amount of tax that is owed dollar-for-dollar, while a tax deduction simply reduces the amount of income on which the tax is charged. For example, if a company earns $4 and pays tax at a 25% rate, it will owe tax of $1. A $1 tax deduction reduces income to $3, tax owed to 75¢, and is therefore worth 25 cents; a $1 tax credit on the other hand can be used to offset the $1 tax liability owed by the company and is therefore worth a full $1. In other words, the value of tax deductions depends on the tax rate while tax credits have full value regardless of the tax rate.

The awardees of the tax credits would have to earn over $6.5 billion in profit collectively to have a tax liability large enough to use the $2.3 billion in tax credits fully at current tax rates.

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Manufacturer Credit

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Incentivizing behavior by doling out tax credits is a poor policy choice because most tax credits suffer from three fundamental problems: they are not "refundable," they are not easily used by anyone other than large corporations and they are not freely transferable.

Tax credits are not refundable in that they can be used only against a current tax liability; if you don't owe the government any tax, then a tax credit has no immediate use to you. The government will not refund or "cash in" the tax credit. Also, strict limitations enacted in the 1980's make it hard for individuals and most closely-held businesses and S corporations to use the tax credits. Lastly, tax credits cannot be transferred freely among taxpayers; you cannot sell a bundle of tax credits to a buyer for a lump-sum payment.

Monetization Strategies

Almost all tax credit monetization strategies rely on bringing an investor that can use the tax credits into the business or activity that produces the tax credits. The tax credits are diverted to the investor who accepts the credits as part or most of its return on its investment.

The three most common transaction forms that use this technique are partnership flip transactions, lease financings (often done as sale-leasebacks) and lease pass-through transactions.

There are two common themes in almost all tax equity deals. First, the tax equity investor is motivated primarily by the tax credits and, therefore, seeks to minimize its exposure to the commercial risks inherent in the activity that produces the credits. Second, the sponsor views the investor as mostly an accommodation party and, thus, tries to minimize the investor's right to share in the upside potential of the business.

All government-sanctioned tax equity transactions put tension on these themes because they require (or should require) the investor to have meaningful equity exposure to either fluctuations in asset value or asset performance.

In a partnership flip transaction, the tax equity investor would purchase an interest in a limited liability company that owns the manufacturing facility. Almost all the economic returns (including the tax credits) would be paid to the investor until it achieves a hurdle rate after which its share of the deal economics would drop to as low 5%. In a flip transaction, the investor takes the risk that the equipment will produce enough revenue and tax credits to repay its investment.

The most suitable stategy is probably to sell and lease back the projects, but the sponsor will need a creditworthy parent to guarantee payment of rent.

In a sale-leaseback transaction, the investor takes title to the equipment and leases it to the sponsor in return for fixed or variable lease payments. The lease payments can be supported by the revenue from the leased equipment or they can be backstopped by a corporate credit and secured by assets other than the leased equipment.

The manufacturer's obligation to pay rent is typically not dependent on the performance of the equipment or whether the revenue and expense projections have materialized. Because manufacturing equipment does not naturally lend itself to project financing, tax equity investors may gravitate to lease financing — where the lessor has recourse to credit and assets other than the leased equipment. Full or partial recourse financing structures may well be the leading tool for enabling "green" manufacturers to monetize the tax credits and other tax benefits of their equipment.

More Challenges

Many tax credit monetization transactions are closed alongside a project financing. Project financing is generally non-recourse financing, where the investors and lenders look to the project contracts to support and repay their investments. Sponsors are generally not required to guarantee or backstop project financings except for certain limited risks that are heavily negotiated.

In a typical project financing, the input or feedstock costs are fixed or hedged by contracts and the offtake or revenue stream is supported by a creditworthy buyer who agrees to buy the output for an extended period of time at a fixed price, with very few or no exceptions. Tax equity investors prefer these types of projects that they can underwrite tax credits in the context of a fairly stable investment.

Some of the manufacturing equipment that qualifies for tax credits is likely to be equipment with technology risk. Some of the credits were used to incentivize equipment that the government thought might not otherwise be built without the tax incentives. The equipment will manufacture components that will be sold into a still nascent industry — the green economy — which itself is greatly dependent on future government subsidies and policies for continued growth. Also, the economic viability of manufacturing equipment is dependent on the ability of the factory owner to purchase and refine raw goods into a saleable product where it is difficult to fix the price of the raw commodities, the refining process and the output components for any considerable period of time. In this way, a manufacturing facility is much like a merchant power plant (one with no firm offtake contract) that has little chance of attracting project financing in a capital-constrained market.

A partial solution to this problem might be the Department of Energy loan guarantee program that was established to support borrowing by a subgroup of these manufacturing facilities. Another solution might be tax monetization structures, including, in particular, leasing structures where the factory owner guarantees all or some of the lease payments to the investor, regardless of whether the equipment or line of business is profitable.

In a sale-leaseback transaction, a bank, insurance company or other tax equity investor buys the equipment from the sponsor and then leases it back to the sponsor. The lessor's investment is the purchase price for the equipment and its investment is repaid through the rents it collects from the sponsor over the lease term plus whatever value is left in the equipment at the end of the lease. The lessor, as owner of the equipment, is entitled to the tax credits and other tax benefits of ownership. The lessee bargains for a reduced rental rate on account of the tax benefits retained by the lessor.

Leasing is attractive to tax equity investors for a number of reasons, none more important than tax and accounting. First, it allows for the separation of the owner — the one who is entitled to the tax benefits — from the user of the equipment. In this way, it allows for a user to continue using the equipment and attract a favorable financing rate because the lessor can subsidize its rate through the use of tax benefits. Second, it allows the lessee, in certain cases, to avoid capitalizing the future lease obligations on its balance sheet, reducing the size of its stated liabilities for GAAP purposes.

Most equipment leases do not follow the project finance model. The lessee's obligation to pay rent is not dependent on the future profitability of the business in which the leased equipment is used. Instead, the lessee's promise to pay rent is typically guaranteed by a creditworthy parent company.

The lessor in a lease financing can claim the tax credits, depreciation and other tax benefits only if the lease is a "true lease" for tax purposes. Simply transferring title to the equipment to the lessor and leasing it back is not enough to enable the lessor to claim the tax benefits. The lessor must be the tax owner of the equipment. To be the tax owner, the lessor must generally have what the tax law calls the benefits and burdens of ownership. The lease term must not run longer than 80% of the expected useful life and value of the equipment and the equipment user cannot have a purchase option to buy the equipment at a bargain price.

A lessor of equipment can elect to pass through the tax credit to the lessee. Only the tax credit is passed through to the lessee; the right to take tax depreciation deductions and other tax benefits of ownership remains with the lessor. To claim the tax credit, the lessee must establish a real position as a lessee with some variability in risk and economics between its payment obligations under the lease and its earning potential from operating the equipment.

The pass-through election brings a number of unique rules into play. First, the lessor, as owner of the equipment, does not reduce its tax basis because it has not claimed the credit. The lessee has no tax basis to reduce because it does not own the equipment for tax purposes. As already noted, the lessee must report income equal to the tax credit over the depreciable life of the equipment. Second, the tax credit may be recaptured if it transfers the equipment (including returning the equipment to the lessor) at any time within the first five years after the equipment is first put into use. Certain transfers by the lessor can also cause the lessee to suffer a recapture liability.

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Special Issues in Leases

One of the key advantages of a leasing structure is that it allows the lessee to guarantee or wrap its lease payment obligations during the lease term. If the lessee's credit is strong enough, it may be able to raise capital through a lease at a lower cost, on a pre-tax basis, than if it held onto the tax credits itself and used another method of financing.

Credits were awarded on 183 projects.

There are a number of techniques that might enhance the returns to both the lessor and lessee.

One of the biggest challenges for investors who offer lease financing is the very high loan-to-value ratio on their investments. Unlike a conventional asset-backed loan where the lender sizes its loan to a comfortable coverage ratio and advances only part of the cost of the asset, a lessor must fund 100% of the cost of the equipment by buying it for fair value and then leasing it back to the lessee.

Various techniques have developed to "right size" the lessor's investment. By far the most common and usually the most efficient is to require the lessee to prepay part of the rent at the outset of the lease. This is economically equivalent to giving the lessor back part of what it just paid the lessee for the equipment. Rent prepayments are governed by complicated tax accounting rules in section 467 of the US tax code. The tax rules treat the rent prepayment as a loan by the lessee to the lessor to be worked off over the lease term. The lessor receives additional tax deductions for the interest it owes the lessee in theory on this loan. Another option is closing a sale-leaseback on only part of the equipment and using the balance of the equipment to secure the lease obligations. In this way, the lessor can structure a deal where its loan-to-value ratio is closer to that of a conventional lender. Other techniques that are sometimes used include requiring the lessee to set aside a portion of the purchase price as a reserve to cover future rent payments or requiring the lessee to post collateral to secure ongoing rent payment obligations.

Another feature commonly employed to both minimize the risk the lessee will be unable to pay rent and allow the lessor to share in some of the operating profits is to have the rent fluctuate based on certain agreed-upon metrics. One example might be to make the rent a fixed percentage of gross receipts from sales of the goods produced by the leased equipment. Alternatively, the lessor might be allowed to sweep all free cash until it has achieved a certain hurdle rate at which point the rents are reduced. Each of these techniques complicates tax accounting rules for lease rental payments, but may be worth the trade off in the right circumstances.

Perhaps the greatest downside of leasing is that it does not permit the lessee to take back its equipment once the lessor has been repaid its investment and earned a return. To qualify as a "true lease," the lessor must own the rights to the equipment at the end of the lease term; therefore, it cannot automatically transfer the equipment back to the lessee. Nonetheless, the tax rules permit the lessee to have a buyout option at a fixed price as long as the price is not less than the projected value at time of exercise or the option is not otherwise certain to be exercised. A fixed-price buyout placed somewhere in the middle of the lease term should permit the lessee to price and evaluate its all-in-yield at the inception of the deal and permit a comparison to its other financing options. Another feature that has seen some use lately is the right of the lessor to sell (or "put") the equipment back to the lessee at the end of the recapture period. Puts create tax risk to the lessor. However, a number of lessors in the current market seem prepared to use them provided the "put" price is set at the fair market value of the equipment when the put is exercised or at a fixed price clearly below what the value of the equipment is projected to have at that time. The put provides the lessor liquidity and more certainty on its investment return. ◎

Court Orders Lender to Continue Funding Defaulted Loan

by Thomas J. McCormack, in New York

Citigroup Global Markets Realty Corp. is appealing a decision by a New York appeals court that required it to continue funding a construction loan even after Citigroup found the borrower to be in default.

The appeal is to New York's highest court. The court must agree to hear the appeal. If it does, it will be the third court to adjudicate the dispute between the parties.

The lawsuit arose out of a 2005 agreement by which Citigroup agreed to provide financing to Destiny USA Holdings, LLC for construction of a "green" development project, a major shopping center and tourist destination in Syracuse.

The case has attracted significant attention both because of the size and nature of the underlying project and because the order to allow the borrower to continue drawing on a construction loan after it defaulted has been viewed as a clear departure from established legal precedent and raises concerns for lenders.

Facts

The project uses a financing model for green economic development that was described as visionary and revolutionary. In addition to the $155 million loan from Citigroup, the financing included funding from the proceeds of bonds issued by the City of Syracuse Industrial Development Agency and equity from Destiny USA itself. The project was designed to be a showcase for using state-of-the-art green technology, renewable energy resources and sustainable design for both its construction and operations. It was also to serve as a means for creating new jobs and a new source of capital in the region. Citigroup funded the project as part of a $50 billion global initiative to address global climate change.

As agent, Citigroup was charged with approving all advances of funds to Destiny USA, regardless of the source. Draw requests were to be funded by Citigroup so long as certain conditions precedent were met and unless Citigroup determined there was a deficiency, meaning the remaining funds available fell short of the expected cost to finish construction.

Destiny USA sued after Citigroup decided there was such a deficiency. The developer was on the verge of making its 27th draw on the construction loan. Citigroup calculated that the project would fall more than $15 million short of what was needed to finish the project.

The alleged deficiency was the direct result of Citigroup's inclusion of tenant improvement costs in the deficiency calculation. Destiny USA contends that tenant improvement costs (which involve changes to the interior of a building, like floor coverings, partitions, heating and cooling systems and other customized finishings, to accommodate tenants) should not be included in the calculation. Destiny USA allegedly did not cure the deficiency within the 10 days allowed after notice, and thus Citigroup determined the loan to be in default and did not fund any subsequent draw requests.

Destiny USA charged in its suit that Citigroup breached the terms of the loan agreement. It asked the court for a preliminary injunction ordering Citigroup to continue funding the loan.

Generally under New York law, to obtain injunctive relief of the kind sought by Destiny USA would require the party seeking that relief to demonstrate that without an injunction it would suffer irreparable harm. Irreparable harm, however, normally cannot be demonstrated where the party seeking injunctive relief has an adequate remedy in the form of calculable money damages. This is usually the case in disputes involving pure money contracts. Simply put, if your damages are monetary and calculable, you are not entitled to injunctive relief.

Reasoning

Thus, although Destiny USA was seeking injunctive relief in what appears to be a pure contract money action, the trial court nevertheless granted a preliminary injunction. A "preliminary" injunction is one of short duration until the court can hear the full case on its merits. However, the trial court decided the merits by finding that the term "deficiency" was not a budget-based term and that tenant */ continued page 28*

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improvement costs could not be used in calculating whether a deficiency existed. It found that Citigroup was in breach of the loan agreement and ordered it to continue funding the loan.

The preliminary injunction was upheld on appeal. The appeals court said Destiny USA had demonstrated a likelihood of success on the merits based on evidence that tenant improvement costs should not be included in deficiency calculations, and further determined that Destiny USA had demonstrated that it would suffer irreparable harm if the injunction did not issue.

A New York court ordered a lender to continue funding a construction loan even though the borrower was in default.

The thrust of the court's decision was based on two so-called exceptions to the general rule that a party cannot obtain preliminary injunctive relief in a pure money damages contract action.

First, although there apparently was no evidence in the record that Destiny USA even attempted to obtain replacement funds to mitigate its damages, the court in essence determined that such a showing was not necessary as the court could take judicial notice of "the economic conditions that prevailed when Citigroup ceased making the loan advances." (Of course, if Destiny USA had been able to find replacement financing, that fact would likely have precluded a claim of irreparable harm.)

Second, the court determined that because of the unique "green economic" financing, for which there was apparently no precedent, it would be virtually impossible to quantify damages. The court did not enumerate reasons for why it considered the financing unique, other than a reference to the parties' prior statements about how the project was "groundbreaking" and "revolutionary," particularly as to the use of federal "green bonds." Instead the court focused more generally on the scope and impact of the project as "unique."

Lessons

Although the Destiny USA decision is limited in its unique facts, counsel drafting loan agreements — in particular construction loans — should be mindful of the following.

The decision has seemingly left wide open an argument by borrowers that they need not even attempt to mitigate damages in times of economic duress when it would be difficult to find another lender, a result hard to square with long-standing mitigation precedents. If nothing else, that portion of the ruling should alert lenders to the importance of drafting specific mitigation clauses in loan agreements. An example is a clause that would specifically require a borrower to mitigate its damages by trying to find another lender if funding stops on the loan.

It is not in the interest of a lender to suggest in the loan documents or other papers that the loan is anything more than a standard loan, even if its ultimate purpose is unique. Otherwise, the lender will open the door to a claim by the borrower that he cannot replicate the financing elsewhere.

Shedding Assets Quickly in Bankruptcy

The credit crunch has not only meant more bankruptcies, but it has also pushed more bankrupt companies into asset sales and liquidations because they are unable to raise the "debtor-in-possession" or "DIP" financing that bankrupt companies use to try to reemerge from bankruptcy as going concerns. Three huge recent bankruptcies — General Motors, Chrysler and Lehman — used a procedure called a section 363 sale to make rapid sales of assets. This is a term that may be unfamiliar to most people in the project finance market.

Two Chadbourne bankruptcy lawyers — Andrew Rosenblatt and Douglas Deutsch — talked with Marc Alpert in mid-March about how the sales work, bidding strategies for potential asset purchasers and what secured lenders can do to protect their interests before an audience in New York. The following is an edited transcript. Rosenblatt and Deutsch have extensive experience representing creditors' committees, lenders and debtors in some of the most complex and high-profile recent bankruptcy cases, including Enron, the Chicago Tribune and Spiegel. Marc Alpert is a corporate partner with Chadbourne in New York.

MR. ALPERT: What are the different ways debtors use to sell their assets in bankruptcy?

MR. ROSENBLATT: There are two ways a debtor can sell assets in a chapter 11 bankruptcy. A chapter 11 case is one where a company files for bankruptcy hoping to work out a deal with its creditors and shareholders that will allow it to continue as a going concern.

It can sell its assets pursuant to a plan of reorganization. A plan of reorganization is essentially an agreement between the debtor and its creditors and interest holders settling the claims of the creditors and the interest holders. The filing of a reorganization plan is the culmination of the chapter 11 process. It comes at the end of the case and in order to implement the plan, the plan needs to be voted on and approved by the creditors and interest holders as well as being approved by the bankruptcy court.

Most of you are probably familiar with the term pre-packaged chapter 11 case and, in such a case, the chapter 11 process can move quickly, but such a pre-packaged plan is the exception rather than the rule.

More often, chapter 11 cases can be very complex, and it is not unusual for a case to last more than a year and, in some cases, several years.

The alternative is for a debtor to sell its assets in a section 363 sale. Section 363 is a section of the bankruptcy code. Traditionally, debtors used section 363 to sell discrete assets, specific business units or subsidiaries, but we are seeing it used more and more to sell substantially the entire business.

Unlike a plan of reorganization or a sale that occurs under a plan approved at the end of a case, a section 363 sale can occur at any time during the chapter 11 process. The recent GM, Chrysler and Lehman bankruptcies demonstrate that section 363 sales can occur very early in the chapter 11 process.

MR. ALPERT: What approvals are necessary for doing a section 363 sale?

MR. ROSENBLATT: Unlike a plan of reorganization that must be approved by creditors and the interest holders, a section 363 sale must only be approved by the bankruptcy court. It is not necessary for creditors or interest holders to approve such a sale, although they certainly have the right to object.

When a court considers whether to approve a section 363 sale, it looks at a number of factors. They are sometimes called the Lionel factors after a case in the early 1980's. The factors are the proportionate value of the assets to the estate as a whole, the elapsed time since the bankruptcy filing, the likelihood that a plan of reorganization will be proposed and confirmed in the near future, the effect of the proposed sale on the ability to put together a future plan of reorganization, how much can be raised from the sale compared to the appraised asset value and, perhaps most importantly, whether the asset is increasing or decreasing in value.

In the General Motors case, the bankruptcy court added four more factors. They are whether the estate has liquidity to survive until a plan can be approved, whether the sale opportunity will still exist at the time of a plan, how likely it is that there would be a satisfactory alternative sale opportunity or a standalone plan alternative as equally desirable or better for creditors if the opportunity to sell is likely to disappear and, finally, whether there is a material risk that failure to approve the sale will cause the "patient" to die on the operating table.

Thee Lionel factors really focus more on maintaining the integrity of the chapter 11 process while the GM factors are more geared toward maximizing value for creditors.

MR. ALPERT: The lack of liquidity in the credit markets has contributed to the spike in section 363 sales over the past couple of years. Do you see this changing in the near term as the economy recovers?

MR. DEUTSCH: Liquidity dried up in the second half of 2008. It became very hard to debtors to borrow what the market calls debtor-in-possession, or DIP, financing. This meant debtors had to sell assets on a more expedited basis. They couldn't wait for the full-fledged normal plan that could take a year or 18 months to conclude. They needed cash sooner so they sold assets. This year, we are seeing a slowdown in section 363 sales, but we have heard that another wave is coming.

What's the Attraction?

MR. ALPERT: Can one of you discuss / continued page 30

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some of the benefits of selling during the bankruptcy proceeding rather than waiting until the end?

MR. ROSENBLATT: One advantage is the ability to realize value on assets that may be losing value. The debtor can file a section 363 motion and try to maximize the recovery for creditors. The primary benefit for buyers is that section 363 sales must be approved by the bankruptcy court and this affords protection from a later challenge. Sales under section 363 generally are free and clear of liens and encumbrances and, although the free and clear language in section 363 omitted the word "claims," bankruptcy courts have been willing lately to provide the maximum protections possible to buyers. Sale orders provide that a section 363 sale will be free and clear of all liens, claims, encumbrances, lawsuits and actions.

The final benefit is that the buyer can benefit from contracts despite the fact that the contracts contain anti-assignment provisions or change-of-control provisions that, outside of bankruptcy, would have prohibited the assignment of those contracts. The only caveat is that personal service contracts are typically not assignable. Courts also have held that certain non-exclusive intellectual property licenses also are not assignable. Therefore, if a buyer is buying intellectual property, it should be careful to have its lawyers advise whether the contracts or licenses are assignable in bankruptcy.

MR. ALPERT: Those are important advantages from the point of view of a buyer. How about disadvantages of sales during bankruptcy?

MR. ROSENBLATT: There are not many. Buyers should be aware that most section 363 sales are done by public auction. It is a competitive bidding process designed to generate the highest price possible. Buyers should be careful not to structure bids that have the effect of dictating the terms of a restructuring as that would allow any sale to be attacked as a sub rosa or disguised plan of reorganization that is intended to circumvent the formal plan approval process.

> So-called section 363 sales can be done quickly, and the buyer takes the assets free of liens, lawsuits and other claims.

How Section 363 Sales Work

MR. ALPERT: So we have covered the advantages and disadvantages of both plan and section 363 sales. Let's focus now on section 363, the process. There are two distinct court hearings in a typical section 363 sale.

MR. DEUTSCH: The process usually takes two to three months. The debtor usually starts the process by identifying a "stalking horse" or party who is willing and able to buy the assets. The debtor negotiates an asset purchase agreement with that stalking horse and, at the conclusion of the negotiation, the debtor drafts a bid procedures motion suggesting how it proposes to sell the assets. There are then two court hearings. The first is a bid procedures hearing. At that hearing, the court approves the bid procedures motion and the debtor goes about marketing the assets.

The debtor wants to find the highest possible bid. If the debtor finds one or more other bidders during the marketing phase, then an auction will be held. The marketing phase usually lasts 30 to 45 days. The debtor holds the auction. The stalking horse bids against the others. A winner is chosen. The debtor then goes to court for the second hearing to ask approval for the winning bid and completes the sale.

MR. ROSENBLATT: People may not appreciate how important the bidding procedures are and how important it is to go into an auction understanding the rules of the auction. Here are two examples of what I mean.

Last year, I was involved in the VeraSun Energy bankruptcy and a section 363 auction that was held in that case. The debtor was selling substantially all of its assets. The assets were ethanol facilities. There were numerous bidders. Some bid on discrete assets; they wanted particular ethanol facilities.

You had another bidder that was bidding on all the assets, and you also had secured lenders who were bidding on the collateral for their loans, which were individual plants.

The mix of bidders made it difficult for VeraSun to evaluate the competing bids. The bidder who bid on all the assets refused to allocate its purchase price among the individual plants; that made it difficult for secured lenders to "credit bid," or bid against the collateral for their loans. The process was less transparent than it might have been with clearer rules. There were a lot of angry bidders. At least two filed objections complaining about the bidding procedures. The auction took 40 hours to complete, which is an unusually drawn-out process.

In another case last year, Chadbourne acted for a secured lender bidding on two businesses that secured its loan to the debtor. The lender had reached a tentative deal with the creditors' committee before the bidding. It agreed to credit bid the entire amount of its secured claim so that it would not have any unsecured deficiency claim left over that would dilute what the debtor would realize from the sale.

The lender really wanted to acquire only one of the businesses, and it wanted the other business to be sold. There was a buyer who wanted that other business.

We made clear at the very beginning of the auction that the credit bid by the lender was a conditional bid — it was conditioned on the lender being the highest bidder for both businesses — and if the lender was not the highest bidder for both, then it reserved the right to allocate its offer price between the two businesses. The other bidder complained the approach was unfair. However, we were careful to make sure the bidding procedures allowed this approach. We had advised the debtor of our planned approach before the auction, and the debtor was fine with it. In the end, we were able to reallocate our bid, until the bid got to a price that we were willing to let the asset go. If the other side had read the bidding procedures with more care, it might have done something to prevent our running up the price of the asset it wanted by continuously reallocating our price between the two assets.

Role of Stalking Horse

MR. ALPERT: Talk a little more about the role of a stalking horse bidder and why anybody would ever want to play that role.

MR. DEUTSCH: The stalking horse bidder has the ability to dictate the terms of the sale. It negotiates the asset purchase agreement. Its bid sets a floor price. The stalking horse bid defines what due diligence is done. The stalking horse bidder gets in early and should have the ability to complete all the due diligence it wants. The stalking horse bidder wins the asset in the end about 70% of the time.

MR. ALPERT: What termination fees or breakup fees are paid to the stalking horse bidder if it is outbid?

MR. DEUTSCH: The typical fee is between 1% and 3% of the final sales price.

MR. ALPERT: Does the fee ever exceed 3%?

MR. GEORGE: Yes. I am sure there are members of the audience who have seen that, although I have not seen it for a long time. Judges lately have been trying to hold fees to 1% to 3%.

MR. ALPERT: Can anyone participate in the bidding process or are there minimum requirements?

MR. ROSENBLATT: It depends, but most bidding procedures limit participation in an auction to qualified bidders and usually what qualifies someone is fairly standard. A bidder must make an irrevocable offer that exceeds the price proposed by the stalking horse. A bidder usually must submit an asset purchase agreement or a term sheet or a markup of the stalking horse's asset purchase agreement. The terms cannot be less favorable than the stalking horse bid. A bidder must submit evidence that it has the financial wherewithal to close the transaction. It must usually make a good faith deposit. It must sign a confidentiality agreement with the debtor.

MR. ALPERT: Do you see bidders using the form of the asset purchase agreement submitted by the stalking horse or does that vary widely?

MR. ROSENBLATT: It depends on the timing of the auction and bidding process. If it is a fairly complex transaction and there is not a lot of time, most bidders mark up the stalking horse's asset purchase agreement. If time is really not an issue, then a bidder might submit an entirely new asset purchase agreement. Mind you, though, that those cost a lot of money, and unlike a stalking horse who is reimbursed if it loses the auction, other bidders do not have that benefit.

MR. ALPERT: Are there any limitations on qualified bidders who are competitors where the debtor would not want information disclosed to that bidder?

MR. ROSENBLATT: Yes. It plays out in whatever conditions the debtor puts on the diligence that the bidder may do. The debtor usually provides as much informa- / *continued page 32*

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tion as is required to make an intelligent bid, particularly financial information. If there are trade secrets, if there are things that are highly confidential, then the debtor has every right to restrict parties from seeing that information.

MR. ALPERT: Is there a norm for the amount that the bidder must deposit with the court as a good faith deposit?

MR. ROSENBLATT: We usually see deposits of 5% to 10% of the price offered by the bidder.

MR. ALPERT: Can an auction be conducted on line?

MR. DEUTSCH: There is no reason why not, but we have not seen any yet in substantial cases.

Stalking horse bidders come away with the assets about 70% of the time.

Protecting Creditors

MR. ALPERT: Let's turn to the perspective of a creditor. You mentioned that assets sold in a section 363 sale are sold free and clear of existing interests. That obviously means that in the sale, the creditors' liens are extinguished. Why would a creditor consent to the sale, and how are creditors protected in the process?

MR. ROSENBLATT: A secured lender does not have to consent to a sale, and there are many protections in the bankruptcy code that protect secured lenders in the sale context.

First, with limited exceptions, a debtor cannot sell an asset that is encumbered by a lien unless the sale price is sufficient to repay that secured creditor in full. Having said that, a secured creditor generally will consent to a sale of assets by auction. Such sales usually yield high returns; it is a good way to maximize the value. Secured creditors usually don't want to own the assets, and auction is the best alternative. There is also some benefit to the secured creditor to let an auction proceed; it is a way to test the market to see what the asset is worth. Another reason why a secured creditor usually will not object to the sale is the fact that under section 363, a secured creditor has an absolute right to credit bid for its collateral. That ensures the asset will not be sold to someone other than the creditor for less than the full amount of the secured debt unless the creditor wants to let the asset go.

Lessons from GM and Chrysler

MR. ALPERT: Let's move on to recent developments and some cases involving bankruptcy sales, starting with the two biggest recent bankruptcies: GM and Chrysler. These cases were handled swiftly through section 363 sales processes. They involved the injections of large sums of money by the US government. Talk about the takeaways from those sales.

MR. DEUTSCH: In Chrysler, the sale was of essentially the valuable assets of old Chrysler to new Chrysler. GM worked the same way. Among the assets left behind were pension liabilities. Some junior creditors appeared to get paid ahead of senior creditors. Specifically, the union pension funds got a majority stake in both companies.

The main takeaway is how fast section 363 sales can proceed. If you have the federal government as a creditor and want to get through bankruptcy quickly, ask it for help. This was a powerful train going down the track, and there was no stopping it.

The second takeaway has to do with the notion of a sub rosa plan. You are not supposed to use the section 363 process to impose a full plan of reorganization. The key is not to determine how much individual creditors will receive from the proceeds of a section 363 sale. You sell the asset. The sales proceeds go into a pot. Then the pot gets divvied up by a plan down the road.

That's not what happened with GM and Chrysler. What we saw in GM and Chrysler is the government dictated the terms that both the senior and junior creditors would receive up front. Maybe this was good for the country and good for a lot of reasons, but it was a clear departure from existing precedent. The Chrysler decision was appealed and affirmed rather matter of factly by the US appeals court for the Second Circuit, which is considered the most influential court in the country after the US Supreme Court.

MR. ROSENBLATT: The cash component that was being provided in the sale was $2 billion. The court said that was greater than the value of all the assets. The cash was going to the secured creditors. The court said the rest of the consideration that was provided — the equity interest in new Chrysler given to the unions — was really consideration given in exchange for new value created by concessions from the unions.

I think the takeaway from Chrysler and GM is there are often competing policies in a bankruptcy case and the court ended up having to balance them. It maximized value for creditors. It relied on the melting ice cube theory and looked at the alternatives if the sale failed to close. The alternative was liquidation.

MR. DEUTSCH: The court was looking for a way to do what it felt was best for the country.

The third takeaway relates to tort claim release. There was a release not only of normal tort claims of which the debtor had notice, but also of future tort claims.

The best way to understand what the court did is to think of an airplane manufacturer who has been in business for 50 years and has lots of its airplanes in use. It decides to sell the entire business to a new company in a section 363 sale. The buyer wants it free and clear of tort claims. State law does not allow such a release. Normally, if you buy all of the assets of a business, you inherit any liabilities tied to tort claims. What can be done? It is inevitable that one of the planes built by this manufacturer in the last 50 years will fail. The seller does not have enough resources to be able to give a credible indemnity.

One way to deal with the problem is to set up a trust and appoint a trustee to represent all future claimants. There are problems with this, and it is not the way they dealt with the problem in the Chrysler bankruptcy.

In Chrysler, the court said essentially that future claims relating to cars that were manufactured before Chrysler filed for bankruptcy would be disallowed. How do you ensure future claimants are being given due process? They need to be put on notice that their claims are in danger of being denied in the bankruptcy proceeding. Judge Gonzalez, the judge in the case, said the following: "Objections touching upon notice and due process issues, particularly with respect to potential future tort claimants, are overruled as to these issues because, as discussed elsewhere in this opinion, notice of the proposed sale was published in newspapers with very wide circulation. The Supreme Court has held that publication of notice in such newspapers provides sufficient notice to claimants whose interests or whereabouts could not with due diligence be ascertained."

The appeals court upheld the judge's decision on this point.

MR. ROSENBLATT: One of the most important bankruptcy policies is the notion that similarly-situated creditors should be treated equally. If you have a case where unsecured creditors and tort claimants are going to recover 5¢ on the dollar, it would arguably be unfair for a future tort claimant to be able to sue a healthier successor to the company and recover 100¢ on the dollar.

MR. ALPERT: So it is better to give them nothing?

MR. ROSENBLATT: No. The way to address the problem is to set up a trust, appoint a counsel for that trust and let the counsel watch out for the interests of future claimants in the bankruptcy proceeding.

MR. ALPERT: Another significant recent case was Lehman's sale of assets to Barclays, which was also done in section 363 sale. Were there other takeaways from it?

MR. DEUTSCH: This was a case where Lehman sold assets that it worried had dropped in value from $70 billion to $50 billion in the space of weeks before bankruptcy. The sale from start to finish was done in a week. The sale price was $1.7 billion in cash and the assumption of $45.5 billion in liabilities. It was estimated that the cash was equal to the value of the Lehman office building in Manhattan. The lesson from the Lehman case is that section 363 sales can be done extremely quickly and with speed come mistakes. Barclays is now being sued by Lehman over whether some of the assets that Barclays got were transferred to it inadvertently.

AUDIENCE MEMBER: What happens if regulatory approvals are required to conclude the sale?

MR. DEUTSCH: It depends on which agency it is but, generally, the sale would be conditioned upon approval. If the transaction is rejected by the regulatory agency, then the debtor would start over. The bankruptcy court would normally not try to usurp the licensing and other regulatory powers of the government agency with jurisdiction over the sale.

MR. ROSENBLATT: The asset purchase */ continued page 34*

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agreement will have a list of conditions to closing. In the auction process, all the bidders agree that the runner up must keep its bid open in case the winning bidder cannot close the sale for any reason, including that the proposed transaction is rejected by a regulator.

AUDIENCE MEMBER: Have you seen any recent cases where the court decided the best offer focused on other aspects besides price, like the ability to close quickly after the sale is approved?

MR. ROSENBLATT: I can't cite you a specific case, but it is not unusual for a creditors' committee to have concerns about the ability of the winning bidder to close or finance a deal, and that absolutely goes into the consideration of what is the highest and best bid.

MR. DEUTSCH: The issue is whether the highest bidder is a qualified bidder. That's why we have bidding procedures. That's why the runner up is asked to be ready to close if the winning bidder cannot close. ◎

Environmental Update

A decision by the US Fish & Wildlife Service in early March to list a ground-dwelling bird called the greater sage grouse as a "candidate species" for protection under the Endangered Species Act is expected to affect permitting for new wind, solar and geothermal projects in the western United States.

The greater sage grouse is found in California, Colorado, Idaho, Montana, Nevada, North Dakota, Oregon, South Dakota, Utah, Washington and Wyoming.

The agency issued three findings about the greater sage grouse on March 5. The most significant is that although the greater sage grouse meets the criteria for listing as "endangered" under the federal Endangered Species Act, it is being listed for now as only a "candidate species" because the agency needs to focus on species that are at a greater risk of extinction. The Endangered Species Act makes it unlawful to "take" (that is harm, harass or kill) any endangered or threatened species and it also requires the government to designate the boundaries of the critical habitat for the species.

Designation as a "candidate species" requires the US Fish & Wildlife Service to review the status of the species each year and propose protection when funding and workload priorities allow, but there is no immediate protection for the species. Instead, the government "encourages voluntary cooperation efforts for these species because they are, by definition, species that warrant future protection." An environmental group has challenged the finding as too weak.

Most of the greater sage grouse habitat is on federal land. The US Fish & Wildlife Service said that 52% of it is in existing greater sage grouse management zones managed by the Bureau of Land Management (BLM). Another 31% is owned by private parties. Other federal agencies — like the Bureau of Indian Affairs and US Forest Service — and states own the remaining acreage.

The US Fish & Wildlife Service designation is expected to affect how the BLM handles requests for rights-of-way over its land. BLM issued Instructional Memorandum 2010-071 on the same day the greater sage grouse was designated as a candidate species to say that the agency plans on wind and solar projects to screen new right-of-way applications to identify whether the wind or solar energy development or site testing and project area includes priority habitat. If so, [BLM will] alert the applicant as early as possible that the application may be denied or that terms and conditions may be imposed on the right-of-way grant to protect priority habitat as supported by NEPA analysis.

Projects located on private land are also subject to guidance. For example, existing draft US Fish & Wildlife Service guidance (issued in 2003 on "Avoiding and Minimizing Wildlife Impacts from Wind Turbines") makes suggestions for how wind tower siting, operation and monitoring should be done to minimize the effect on wildlife. This guidance recommends avoiding putting up turbines in a manner that fragments contiguous habitat for certain species like the greater sage grouse.

Some private landowners have entered into "Candidate Conservation Agreements with Assurances" with the US Fish & Wildlife Service. Landowners who agree to take conservation measures to protect certain species receive assurances that no additional restrictions will be imposed on use of their land if the species are later listed as endangered.

States like Wyoming and Colorado have also have taken steps to conserve the greater sage grouse and its habitat.

Developers and project lenders should be sure to do their diligence.

Climate Change

The US Environmental Protection Agency is expected to regulate greenhouse gas emissions in the United States unless blocked by Congress. Key members of Congress want to block EPA from acting, but that requires an affirmative vote by Congress which, in the current era of gridlock, may be hard to achieve.

There is considerable uncertainty around three basic questions when it comes to what EPA might do. The questions are what stationary sources of greenhouse gases will be regulated, when the regulations will take effect and how major stationary sources of greenhouse gas emissions will comply with the existing "Prevention of Significant Deterioration," or "PSD" program.

EPA is required to regulate utility and industrial boilers, turbines and other major stationary sources of greenhouse gases under the Clean Air Act after finding on December 7, 2009 (effective on January 14, 2010) that elevated concentrations of greenhouse gases like carbon dioxide (CO_2) in the atmosphere endanger the public health and welfare of current and future generations and that the combined emissions from new motor vehicles and new motor vehicle engines contribute to pollution.

The "candidate species" listing for the greater sage grouse is expected to make it harder to build new wind and solar projects in the western United States.

Although the endangerment finding does not directly involve stationary sources of greenhouse gases, EPA is required to issue regulations controlling such gases under the PSD program. The PSD program requires permits to construct new and major modifications to major sources (those with a potential to emit at least 250 tons per year of a regulated pollutant) and use of the best available control technology — called "BACT" — to control emissions of such pollutants.

Eight Democratic Senators, including Jay Rockefeller (D.-West Virginia), sent a letter to EPA on February 19 asking the agency to provide a "clear understanding" of the agency's responsibilities with respect to the regulation of greenhouse gases and processes to carry out those responsibilities. EPA responded on February 22, 2010. Its letter provided a road map of what it intends to do.

The agency said it does not plan to require stationary sources to get Clean Air Act permits to cover their greenhouse gas emissions in calendar year 2010.

It anticipates phasing in permit requirements for large stationary sources of greenhouse gases */ continued page 36*

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beginning in 2011. Initially, only facilities applying for permits under the Clean Air Act because of emissions of non-greenhouse gas pollutants will have to address greenhouse gas emissions in their permit applications.

The agency expects to address greenhouse gas emissions from other large emitters of greenhouse gases in the last half of 2011. Through 2013, EPA expects that the threshold for needing a permit will be substantially higher than the 25,000-ton threshold that EPA proposed earlier.

EPA does not intend to require the smallest sources of greenhouse gases to have permits covering their emissions any sooner than 2016.

The question of what major sources of greenhouse gases will be regulated has not been resolved. Despite legal arguments that EPA cannot increase the threshold of 250 tons per year that triggers limits under the existing PSD program, EPA is considering raising the threshold to at least 25,000 tons per year of CO_2 equivalent. A CO_2 equivalent is a measure of the global warming potential of a greenhouse gas.

EPA hinted at how it intends to answer the question of when major sources of greenhouse gases will be subject to regulation in late March. On March 31, 2010, it issued a decision after reviewing a ruling by the Environmental Appears Board that required EPA to consider CO_2 emissions and apply BACT before issuing air emissions permits under the PSD program. The agency said any tightening of PSD regulations should not take effect until after regulations it issued on greenhouse gas emissions from motor vehicles takes effect. These regulations were issued on April 1 with an effective date of January 2, 2011. Greenhouse gas regulations for stationary sources would apply to any permits issued after this date, regardless of when the application was received. Thus, it is not clear that a developer will be able to avoid the contemplated restrictions by applying today for a permit. Opponents of projects may seize on this as an incentive to stall development work.

There is no answer yet to the question of how greenhouse gas emissions will be controlled. EPA has not yet identified what is BACT for CO_2 emissions. There are no CO_2-specific emissions control devices, and technologies such as carbon capture are not yet commercially available.

Meanwhile, Republicans, led by Senator Lisa Murkowski (R.-Alaska), the senior Republican on the Senate Energy Committee, are lining up behind a joint resolution to disapprove of EPA's endangerment finding. EPA has acknowledged that if this resolution is enacted, it will not be able to regulate emissions from greenhouse gases since an endangerment finding is a prerequisite to such legislation. There have also have been a number of lawsuits filed in court to force the agency to reconsider the endangerment finding. Senator Rockefeller introduced a bill in March that would prohibit the agency from regulating CO_2 and methane from stationary sources for two years.

As long as the uncertainty remains, lenders may decide there is less risk in lending to renewable energy projects that do not emit any greenhouse gases.

— contributed by Sue Cowell in Washington

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