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A Hot Solar Market

There are two types of solar projects: photovoltaic, where sunlight is converted directly into electricity through solar panels or thin film, and concentrating solar power or solar thermal projects, where sunlight is directed by mirrors or lenses on to a heat exchange medium, the heat is used to boil water to make steam, and the steam turns a steam turbine. Both markets are growing rapidly.

Photovoltaic projects may involve solar panels mounted on roofs of big-box stores, schools, hospitals and commercial office buildings or on special structures erected over parking lots. Utility-scale photovoltaic projects can involve massive arrays in the desert mounted at angles to face the sun. The following is a transcript of a discussion among the heads of five companies that develop or install photovoltaic systems. The discussion took place at the Infocast "Solar Finance and Investment Summit" in San Diego in April.

The panelists are Karen Morgan, president of Envision Solar International, Jeff Wolfe, founder and CEO of groSolar, Arno Harris, CEO of Recurrent Energy, Andrew Beebe, president of EI Solutions, and Paul Detering, CEO of Tioga Energy. The moderator is Keith Martin from the Chadbourne Washington office.

MR. MARTIN: Working in an industry that is so heavily dependent on government subsidies can be like jumping and hoping someone will hand you a parachute. Solar projects qualify for large tax subsidies. Congress extends the tax subsidies, then they expire, and then it extends them again. Why does it make sense to commit so much effort to an industry that is so heavily reliant on the whims of the government? / continued page 2

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A NEW FARM BILL enacted in late May made several changes in law that affect segments of the US energy market.

The biofuels market is the most significantly affected.

The bill includes a new tax credit of $1.01 a gallon for producing cellulosic biofuel. The new credit is reduced to 40¢ a gallon if what is produced is ethanol and to 31¢ a gallon if it is another form of alcohol. (That's because these forms of fuel also qualify potentially for other existing tax credits.) The credit can be claimed on fuel produced during the period 2009 through 2012. The haircut in the credit for ethanol and other alcohol fuels only applies through 2010, unless Congress extends two / continued page 3

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MR. DETERING: We have to trust that the government will act sensibly and provide incentives that will remain on the books long enough for the industry to make it on its own. The government needs to do this to reduce our dependence on foreign oil and to encourage a shift from old forms of energy to renewable forms of energy. Photovoltaic solar is still too expensive to compete at parity with other forms of electricity. The hope is that the subsidies will accelerate the day when it can compete.

Solar electricity is at least two times more expensive than electricity from fossil fuels. The gap is expected to close by 2012.

MR. MARTIN: Andrew Beebe, how much does solar electricity cost per kilowatt hour compared to electricity from fossil fuel?

MR. BEEBE: You mean pre-subsidy?

MR. MARTIN: Yes.

MR. BEEBE: The comparison is unfriendly. But as the interest in solar grows, more people get into the business and the cost curve declines while the cost curves for plants that use coal, gas or other forms of energy stay fairly fixed, giving this industry a really interesting end point. That is a fun thing to go after.

MR. MARTIN: Arno Harris, how much does solar electricity cost per kilowatt hour currently, pre-subsidy?

MR. HARRIS: Without an investment credit and direct state incentives, you are talking about something like 30¢ a kilowatt hour.

MR. MARTIN: Compared to what price for electricity generated from fossil fuels?

MR. HARRIS: At a wholesale level, probably 6¢ or 7¢ a kilowatt hour.

MR. BEEBE: It should be a retail comparison, right? So when you look at the avoided peak cost, the electricity price is more like 15¢ a kilowatt hour. Solar electricity is still double the retail rate.

Jeffrey Immedlt gave an interesting talk recently in which he answered your question. GE does not operate in a market setting. Much of what it does is in areas that are heavily regulated: for example, media, finance, health care. He was talking about why GE got into manufacturing jet engines and turbines, one of the more profitable areas. It was because of government incentives. We are still in the early days of a new industry and such industries are often seeded because the government wants to see them grow and provides inducements for people to get into them.

MR. MARTIN: Jeff Wolfe, you must obviously believe the gap between fossil and solar electricity will close fairly rapidly or you wouldn't be putting so much time into this market. What do you think will be the time frame?

MR. WOLFE: It depends on a whole host of factors, including the investment credit, state subsidies and the price of fossil fuels. As fossil fuels go up in price, electricity prices also increase. We have done a better job as a country of raising electricity prices in the last few years than we have of lowering PV costs, but either direction is fine. [Laughter] It appears that if enough plates spin in the right direction that we will have grid parity somewhere around 2012 to 2015.

MR. MARTIN: Paul Detering, does that time frame sound right?

MR. DETERING: We are a little bit more optimistic. I think the decrease in cost of PV will come about more quickly than 2012 to 2015. Maybe it is because I come from the technology industry and from venture-backed start ups and know lots of people are tinkering with improvements in photovoltaic technology. To me, the bigger issue is how do we get these new technologies deployed more rapidly.

MS. MORGAN: Let add a couple points here. It is important to see some standardization on the financing side so that we can do more of these projects. That is one of the major hurdles that we have: just getting order around the chaos. We have a slightly different perspective, because our company is very challenged by cost in that we focus on parking structures. Our projects are more expensive than just putting solar panels on rooftops. However, we see an opportunity to build esthetically beautiful environments in and around these solar parking structures. Our focus is also not just the United States. Consequently, we do not feel encumbered by the existence or lack of a US investment tax credit. Part of our mission is to drive wider deployment of solar worldwide because scale brings down cost.

Industry Economics

MR. MARTIN: Andrew Beebe, keeping the focus for now on the United States market, how important is a 30% investment tax credit for these projects? How important are utility rebates? Is there a way to quantify their importance?

MR. BEEBE: It's pretty binary. Without both of those combined, at least in California where we do 80% of our business, the deals just don't happen.

MR. MARTIN: Arno Harris, is there a way to quantify their importance to the economics of a deal?

MR. HARRIS: We cannot compete today for mainstream customers that are not necessarily ideologically motivated and are not interested in paying a premium for solar electricity without the investment credit.

MR. MARTIN: Jeff Wolfe, in how many states are there utility rebates?

MR. WOLFE: There are 20 with wildly different designs and patterns.

MR. MARTIN: Describe how they work in California.

MR. WOLFE: There is a commercial rebate, which is performance based and where for every kilowatt hour you generate you get both the retail electricity rate and a performance-based incentive that varies depending which utility service territory you are in. The incentive payment is either 22¢ or 26¢ for every kilowatt hour you generate for the first five years of the project.

MR. MARTIN: And that is a cash payment by the utility to whom?

MR. WOLFE: To the system owner.

MR. MARTIN: Can anyone describe how the program works in New Jersey?

MR. WOLFE: They are still figuring it out. I have been in the New Jersey market since 2004 and the / continued page 4

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existing tax credits for ethanol blenders and small ethanol producers beyond their current expiration date in 2010. Congress suggested that fuel will be considered cellulosic biofuel if it is produced from "dedicated energy crops and trees, wood and wood residues, plants, grasses, agricultural residues, fibers, animal wastes and other waste materials, and municipal solid waste."

It is not enough merely to produce the fuel. The producer must also do one of four things with it to qualify for tax credits. He or she must either blend it with gasoline or a "special fuel" and sell the mixture to someone else who will use the mixture as fuel in his business, sell it to a blender who will mix and sell the mixture to such a user, sell the biofuel to someone who will use it directly as fuel in business without mixing, or sell the biofuel at retail, without mixing, to people who put it directly in their fuel tanks.

The new credit can only be claimed on fuel that is both produced and used in the United States. If the fuel is alcohol, then it must be at least 150 proof.

Other ethanol producers suffered a nickel reduction in their tax credit. The farm bill reduces an existing tax credit of 51¢ a gallon for blending ethanol with gasoline or for selling ethanol at retail to 46¢ a gallon. The change takes effect next year, but only if at least 7.5 billion gallons of ethanol are produced or imported into the United States during 2008. If US ethanol falls short of this figure, then the nickel reduction will be delayed until the first year after the target is hit.

The bill extends a US tariff on imported ethanol for another two years through 2010. The tariff is 54¢ a gallon. It had been scheduled to expire at the end of this year. A fair amount of ethanol enters the US duty free or at reduced tariffs under treaties. Blenders who blend imported ethanol with gasoline can still claim the existing 51¢ blender's credit even though the ethanol comes from overseas.

The bill allows 50% of the cost of new equipment and buildings put in / continued page 5

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program worked well in 2004 and 2005. They are trying to transition to a solar renewable energy credit market where utilities must purchase a certain number of megawatt hours of SREC credits. Those SREC credits have a capped value of 71¢ a kilowatt hour, or $710 a megawatt hour, but the utilities feel that they can probably purchase them for less. The idea of the New Jersey program, although it is not fact yet, is that a developer will sell his SRECs under a long-term contract to a utility or other purchaser at a price that creates enough value to finance a project.

MR. MARTIN: So the SRECs can be sold separately from the electricity?

MR. WOLFE: Correct.

MR. MARTIN: And for how long a term will the utility buy the stream of credits?

MR. WOLFE: The renewable portfolio standard is a permanent regulation, and they need to continue to buy SRECs for their own generation to fill that RPS, and it's an escalating requirement through 2020. It's a long-term need.

MR. MARTIN: What other states have good utility rebates?

MR. BEEBE: Hawaii.

MR. DETERING: Oregon has a program that's interesting, Colorado.

MR. WOLFE: Connecticut, Massachusetts.

MR. MARTIN: Paul Detering, suppose a solar PV project costs $100. The investment credit is $30. The ability to depreciate the project over five years is worth $26. So you have $56 so far covered. How much of the remaining cost is covered by a utility rebate?

MR. DETERING: These numbers are evolving and moving because the rebates, specifically in California, are coming down. That said, we look at it and say it's roughly a third, a third and a third. A third of the project cost is covered through tax benefits. A third is usually covered by a state rebate. A third comes from the underlying economics of selling electricity.

Insolation

MR. MARTIN: Let's move to another topic. Andrew Beebe, what is insolation?

MR. BEEBE: Insolation is the amount of sunlight that hits a given space.

MR. MARTIN: And how is it measured? How is it expressed?

MR. BEEBE: There is a theoretical maximum of 1,000 watts per meter squared. We look at it in a given area based on NREL data; it is surprisingly well measured. We assess the financial viability of projects in different regions based on three measures: policy, prevailing electricity rates and the sunlight. We look at them in that order. Insolation is actually third on the list. To echo what Jeff Wolfe said, we are seeing extraordinary increases in electricity rates in California, and we expect that to continue as the state moves away from coal-based power. So Pasadena, the Los Angeles Department of Water and Power and Southern California Edison, just in our little neck of the woods in southern California, have now all in the last three months announced 10+% rate hikes, with additional rate hikes of roughly the same amount expected next year. The trailing average in California for the last 30 years has been 5.8%. The point is that electricity rates are a much more important driver for solar projects than insolation.

MR. MARTIN: Sticking with you, Andrew Beebe, what are the top three states, given that checklist, for solar?

MR. BEEBE: It is an extraordinarily challenging question to answer because the market is such a moving target and, given that a development time frame of six, optimistically, but more like 12 to 18 months on a given project, we have to answer the question — what are the likely places to turn systems on in 12 to 18 months? — if we are talking about a

> Sunlight is third in importance when it comes to choosing sites for solar projects.

fresh start from today. In the 12- to 18-month time frame, California absolutely would remain number one, but behind that I think it's a little bit of a crap shoot. Hawaii and Oregon both offer good state tax benefits, but the tax benefits are challenging to use given that there are few companies with large enough tax bases in state to use them. New Jersey, if it works out the kinks in its new program, will be an obvious number two. We are spending a great deal of time in Florida, Texas and Arizona at a legislative level because we think that all three of those states could pop in the next 18 months.

MR. MARTIN: Arno Harris, same top three list?

MR. HARRIS: The southwest delivers the best sunlight in terms of insolation. But to prove Andrew Beebe's point about the relative importance of sunlight, Germany, which gets half the insolation of most of the United States, is the largest solar market in the world because of the rich incentives.

MR. MARTIN: Jeff Wolfe, come back to insolation. Is insolation so unimportant that you could do a solar business anywhere in the United States? For example, could you do it in Seattle where it rains all the time? [Laughter]

MR. WOLFE: The United States is almost unfairly endowed with sunlight as we have been endowed with oil and coal and wind and almost any resource we want. You look at the insolation, which I prefer to call a radiance map so it that is not confused with insolation, and Vermont has about 30% more sunlight than Germany does. Southern California has about 30% more sunlight than Vermont has. The utility rates in Vermont are 30% to 40% higher than in Arizona. Other things being equal, it makes more sense to build a solar project in Vermont than Arizona. The only place in the mainland U.S. that is like Germany is Seattle, and I believe Seattle is better than or equal to most of Germany. So anywhere in the continental U.S., and even parts of Alaska, are wonderful solar sites.

Conversion Efficiency

MR. MARTIN: Karen Morgan, let me shift gears. What type of technology are you using, and how efficient is it at converting sunlight into electricity?

MS. MORGAN: We use both thin film and solar PV glass. The efficiency is far greater in the glass than the thin film. The biggest challenge with thin film is the efficiency, but we are customer centric. There are sites where thin film is more appropriate. The challenge is financing it. Thin film may be better suited for some microclimates — */ continued page 6*

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service in Kiowa County, Kansas and surrounding areas to be deducted immediately. The rest of the cost can be depreciated using the regular depreciation schedules. This is a part of Kansas that has been hard hit by tornadoes. It applies only to equipment put in service between May 5, 2007 and December 31, 2008. There is an extra year to put buildings in service. Most power projects are considered "self constructed." Significant construction cannot have started before May 5, 2007.

Finally, the bill bars US Customs from changing the way it calculates duties on imported goods before 2011. Duties are currently collected on the price actually paid. However, in cases where goods are not purchased directly from the manufacturer, the duty can be based on the wholesale price charged by the manufacturer, ignoring resales by middlemen, if the initial sale was at arm's-length and the goods were clearly destined for the United States.

Customs proposed in January to start charging duties based on the last sale price before the goods enter the United States. This has importers up in arms over the prospect of having to pay higher duties. Congress blocked implementation of the proposal until Customs can collect data about its economic impact.

MASTER LIMITED PARTNERSHIPS cannot own power plants, the Internal Revenue Service said.

Master limited partnerships — called MLPs — are partnerships with units that are traded on a stock exchange or over-the-counter market. Developers like them because they can be used to raise equity more cheaply; investors are willing to pay a higher multiple for units because the units can be resold into a liquid market. In addition, the partnerships do not pay income taxes. The partners are taxed on their shares of partnership income directly. Finally, they are good vehicles for rolling up assets or small businesses because the units can be used as a currency to make acquisitions.

As a general rule, any */ continued page 7*

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for example, where there is fog.

MR. MARTIN: How efficient are panels versus thin film in converting the energy in sunlight into electricity? 15% conversion efficiency? 12%? 16%?

MS. MORGAN: Fifteen to 18% for panels and about half of that on the thin film.

MR. MARTIN: Jeff Wolfe, how much has that efficiency percentage changed recently?

MR. WOLFE: I'm a fan of evolution rather than revolution, and it has been an evolutionary change. You know, when I got into the industry 10 years ago, your average crystalline pod was in the 12% range. It is now 15% on a panel basis. There are outliers, obviously. The cad-tel thin film was in the 6% range. I believe it is now approaching 10%. ASI transparent panels were in the 6% to 7% range. ASI panels are still in the 6% to 7% range.

MR. HARRIS: One of those interesting things from the perspective of a developer is we are at the edge of the commercialization of a lot of these technologies. We have seen a lot of upstream investment in manufacturing and comparisons of different technologies in the lab and the new technologies are now starting to move into manufacturing. Developers are at the tail end of the value chain in receiving that technology and deploying it on a commercial basis. The challenge is to get those technologies out of the lab and on to rooftops. We don't know until they are put into use how viable they are commercially and in terms of the predictability of their performance over a long term, their stability in an exposed environment, and ultimately the creditworthiness of the warranty behind them has as big an impact on whether we will deploy them and how we use them as technical performance.

MR. MARTIN: Andrew Beebe, are the choices between crystalline and thin film? Are they at different ends of a spectrum? Describe the range of possibilities.

MR. BEEBE: For five years, we have been doing large-scale commercial installations in many different locations. For the first four years, these were design-build-transfer contracts where we installed and sold solar systems. In such transactions, there was usually a willingness on the part of the customer to take bigger risks because the customer saw warranties from manufacturers and wanted to try the latest thing. We wanted to push the envelope.

Solar panels convert 15% to 18% of the energy in sunlight into electricity.

We are now making the transition — and I would call it revolutionary, not evolutionary — to financing of systems around a power contract with the customer rather than a sale of the project. In fact, 80% of our deals over the next 12 months will be power contract deals, or PPAs.

In a PPA market, developers have a very different view. They want systems that are bankable and financeable over long periods of time. So we are seeing — I don't know if it is a regression or progression — to a more predictable model of technology. Therefore, to answer your question, we will continue to focus on baseline polycrystalline technologies because they are bankable and they work. And that's probably a good approach for the industry because we won't see projects having massive technical or systemic failures across multiple sites.

MR. MARTIN: Paul Detering, have you used thin film and if so, what problems, if any, have you had with it?

MR. DETERING: We have not deployed any thin film. We have proposed projects with thin film. I actually am encouraged and look forward to deploying newer technologies. What I like to say is that we want to be on the leading edge, but not on the bleeding edge of the new technology. We need to work very closely with the sources of capital that back us for these projects and make sure they are comfortable with the economics as well as the reliability of the technology, not just in the first year, but also over the life of the projects to make sure that we can pay back the debt and earn a decent return.

Leases v. PPAs

MR. MARTIN: Karen Morgan, do you use leases with customers or power purchase agreements and whichever one you use, why?

MS. MORGAN: The answer is both, and it is driven by the customer's situation. PPAs are the choice *du jour,* but leases work as well.

MR. MARTIN: Why are PPAs the choice *du jour*?

MR. HARRIS: The difference is in who carries the risk of performance. The reason why PPA financings are becoming more common is today's mainstream customers don't want to take the risk of operation or ownership. They really just want to buy electricity by the kilowatt hour.

MR. DETERING: Each customer has to decide what business he or she is in. Is the customer in the business of owning, operating and maintaining equipment on a roof or parking structure or the back side of a hill? Or is the customer in the business of doing something else and letting a power company own, operate and maintain the systems?

MR. MARTIN: I can see you guys are good salesmen. How much difference is there really for a solar panel between leasing it and buying the electricity it produces? There is not much maintenance required.

MR. BEEBE: For the last 18 months, our value proposition is to offer customers three options. The customer can buy the system outright, lease it or enter into a PPA to buy the electricity. If the customer wants a PPA, then we will go out and find the customer the best deal. It is an honest broker approach. Customers really appreciate it. We don't take anything off the top in any of the three scenarios. So I feel like we are in a position to provide data on the reactions from customers. Every single customer will look at those three options, and everyone will walk from the lease for exactly the reasons these guys are articulating.

MR. MARTIN: Jeff Wolfe, which model do you use and why?

MR. WOLFE: We use what the customer wants, and that's usually a PPA because customers are interested in buying electricity and not in owning the generating assets. Most manufacturers, hospitals, schools — you / continued page 8

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partnership whose units are publicly traded is taxed like a corporation.

However, the US tax laws make an exception. An entity will remain a partnership if at least 90% of its gross income each year is passive like interest and dividends. It is also good income if the partnership's earnings are from producing, transporting or processing any mineral or natural resource, "including fertilizer, geothermal energy and timber."

Many people have asked whether it is "processing . . . geothermal energy" to turn it into electricity. The IRS said no in June.

The agency said in a private ruling that power plants that use geothermal energy, natural gas, wood chips, refined oil products and coal do not "process" minerals or natural resources.

It said, "The use of the word 'processing' in the energy industry means a specific type of downstream activity encompassing refining and certain petrochemical activities, but this meaning does not include" generating electricity. It pointed to language in Congressional committee reports when the master limited partnership rules were enacted that said it is processing oil to run it through a refinery to make gasoline, but not to use it farther downstream to make plastics.

The ruling was odd because most taxpayers withdraw their ruling requests rather than have the agency issue an unfavorable ruling. In this case, the taxpayer may have wanted to put the IRS on record to discourage competitors from attempting to use MLPs for power plants.

The ruling is Private Letter Ruling 200821021. The IRS made it public in early June.

The agency opened the door last year to use of master limited partnerships by companies that own electric transmission grids by ruling privately that such grids are considered largely real property. Rents from real property are considered good income for an MLP.

BIOFUEL PRODUCERS are being challenged by the IRS on two issues on audit.

One is how the plants / continued page 9

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name it — have a certain amount of capital dollars, and they want to use those capital dollars in their core businesses and not in what is really a side business.

MR. MARTIN: Arno Harris, you scour the market for potential customers, people who want to put panels on their roofs or on the ground. What's your business proposition to them?

MR. HARRIS: Our focus is on what we see as a vast underserved market: rooftops that are sitting vacant on leased properties. If you look broadly across the types of roofs that we think are attractive, 40,000 square feet or bigger in solar-friendly states and in utility territories where the electricity rates are relatively high, we see 60% or more of rooftops being unaddressed by a market that has traditionally focused on owner-occupied buildings. Leased properties face a number of challenges that we call the lease barrier and that have to do with the fact that triple net leases create some disincentives between owners and tenants around ownership. They also represent a bit of a challenge from a financing perspective, because unlike, say, a Wal-Mart or a Kohl's, you have a building in which you may not have a 15-year tenant with great credit that wants to sign a 15-year power purchase agreement. We have focused on developing a set of structural and financial solutions that allow us to make those types of properties financeable by our partner, Morgan Stanley, and we think it opens up a massive opportunity for us.

MR. MARTIN: Paul Detering, what is your business proposition to customers?

MR. DETERING: At the end of the day, it's pretty simple. Most of the time, but not always, we can show them a lower cost of electricity compared to what they are paying today. The second part is, as they look into the future, they fear an escalating rate of increase in electricity prices. The second thing we offer is the ability to hedge against those future increases. Third, and certainly not least, is the fact that they want to move to green renewable energy and, in some cases, they are willing to pay a premium for that as well.

MR. MARTIN: Karen Morgan, you have a very different proposition. What is it?

MS. MORGAN: I would flip what Paul Detering is saying in terms of how we position our value proposition. It is very much about the esthetics and the beautification of ugly parking lots. As our chief operating officer likes to say: "The entryway to your facility is no longer at the lobby. It's at the curb cut." The customer may be able to cover part of the cost of the electricity by charging drivers extra to park under the solar shade.

Even in the best states for solar, at least 60% of rooftops with 40,000 or more square feet do not yet have solar panels.

MR. MARTIN: Jeff Wolfe, you've been in this business perhaps longer than anybody else on the panel. How have you seen the value proposition to customers evolve, if at all?

MR. WOLFE: It has gone from being a pure values proposition to both a values proposition and economic proposition. I think what is often misunderstood is that while the financial models need to work for your business, but financial models alone don't sell a project. We have seen many projects with great finances fall apart because the customer just didn't want to do it at the end of the day. There had been a movement away from selling on the values, which is how pretty much everything else is sold in this country: value, want, desire. Now things are moving back. It is easier to sell something that has value if it is cheaper.

MR. HARRIS: In our market, our customers really aren't so much interested in fixing their long-term costs of power. They are much more interested in getting green power and just making sure that they are never exposed to an above-market price. We tend to enter into contracts that offer an indexed rate that rises along with utility rates, but with a discount to the utility rate. The result is very different. Customers who want hedges are trying, in a sense, to capture the option value of the solar power system up front. Our model makes us more of an energy company.

Contract Terms

MR. MARTIN: Andrew Beebe, how long would you typically enter into a lease or power purchase agreement with a customer?

MR. BEEBE: We have never done a lease. We have offered them, but never done them. We actually don't enter into the PPAs. We do it through partners. They are for 12 years on the low end and 25 years on the high end.

MR. MARTIN: Paul Detering?

MR. DETERING: We look typically at 15 to 20 years, but in some cases as short as 12 years. A short contract makes it harder for the economics to pencil out. The economics look better with longer contracts. Adding to what Arno Harris said, what we are seeing today in the marketplace is a lot of customers who see solar as a hedge against rising electricity prices. We have structured proposals where we essentially provide a floating rate off of some agreed benchmark, but we have not had many takers.

MR. MARTIN: Karen Morgan, how long are your contracts typically?

MS. MORGAN: They run 20 to 25 years for PPAs, shorter for leases.

MR. MARTIN: Jeff Wolfe, what do you do about vacancy risk? If you need the economics of a contract that runs 12, 15 or 20 years, what do you do about the possibility the customer will go out of business or move?

MR. WOLFE: I don't offer the PPAs myself; we work with other parties to do that. It really comes down to doing credit analysis and creating a large enough pool of projects that any one project doesn't put the whole program at risk.

MR. MARTIN: Arno Harris, you have vacancy risk. What do you do about it?

MR. HARRIS: Our approach is basically similar to what Jeff described. We look to mitigate that risk through the portfolio of projects that we have operating. We are very careful in the site selection.

MR. DETERING: Let me add to that. The other thing that we do is credit analysis very early in the sales cycle. We look at what the underlying credit of the offtaker is, and we have developed some proprietary tools that we / continued page 10

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are depreciated for tax purposes. The IRS position is that plants that make liquid fuels from corn or other "biomass" must be depreciated over seven years on grounds that they fall into depreciation class 49.5, which covers "assets used in the conversion of . . . biomass to heat or to a solid, liquid or gaseous fuel." Many plant owners have been depreciating their plants over five years by arguing that they are in the business of manufacturing chemicals. The difference in depreciation is worth 2¢ per dollar of capital cost. The loss in tax subsidy to a typical ethanol plant is about $4 million.

The agency explained its position in an internal legal memorandum that it made public in April. The memorandum is ILM 200814025.

Many US biofuel producers receive annual payments from the Commodity Credit Corporation, which is part of the US Department of Agriculture. The payments are tied to increases in annual output of biofuels made from eligible commodities. The eligible commodities include corn, barley, grain sorghum, oats, rice, wheat, soybeans, sunflower seeds, canola, crambe, rapeseed, safflower, sesame seeds, flaxseed, mustard and cellulosic crops such as switchgrass and hybrid poplars.

Some biofuel producers are taking the position that the payments do not have to be reported as income. The IRS issued a "coordinated issues paper" calling the attention of its field agents to the problem.

The IRS said the payments are a supplement to earnings and are no different than the revenue the producers collect from selling the output from their plants. The coordinated issues paper is LMSB-04-0308-019. The agency released it in April.

A SOLAR DEVELOPER installing solar panels as part of a new low-income housing project did not have to reduce the 30% solar tax credit, even though the housing project was financed in part with tax-exempt bonds and the owners of the project qualified for / continued page 11

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use so that we don't waste sales time up front.

MR. MARTIN: Does anybody on the panel have a sense of the growth in the PV market? Is there any way to measure it?

MR. WOLFE: A lot of money has been put into the manufacturing side and the technology side of the solar business. Manufacturing will catch up with demand. Somebody will figure out how to stamp the wickets. On the financial side, it is extremely complex financing. A lot of very good people are working on it. We are getting it. Once the financial side gets worked out, we will know what our financial markets can do. The stumbling block is that at some point these things need to go on a roof and we need a roofer, electrician, mechanic, somebody to build these projects. The challenge will be how to scale up to the ability to move from putting megawatts to gigawatts out into the field in a very short order.

MR. MARTIN: Arno Harris, how long do crystalline panels last? What's their useful life?

MR. HARRIS: Twenty five years is the warranty life. The actual life may be a lot longer.

MR. MARTIN: How rapidly do panels lose value or how rapidly do they degrade in terms of energy conversion?

MR. WOLFE: The theoretical and warranted rate of degradation tends to be about .8% per year in minimum power output. The panels are affected by sunlight and heat. The less sunlight and heat you put on them, oddly enough, the longer they last.

MR. BEEBE: So you guys cover your panels?

MR. WOLFE: Right. It makes them last a lot longer. [Laughter] Even in the southwest where it is very hot and very sunny, you will find maybe a .5% percent degradation or less, and that varies with panel manufacture and technology. Some are finding about a .25% degradation per year.

MR. BEEBE: We model .75% for PPA transactions.

MR. MARTIN: Does the value decline commensurately with the degradation in efficiency of conversion?

MR. BEEBE: One area of continuing discussion is the residual value of these systems. I think that's a TBD — a to be determined — because, unfortunately, you can't just look at the degradation curve to model the efficacy of the system seven years from now. It is a more complicated equation that must take into account the rate of technological change and the future interest of the market in solar.

Many customers see solar as a hedge against rising electricity prices.

MR. WOLFE: There are also very different residual values depending on whether the system is left in place or whether it is moved and reinstalled elsewhere.

MR. DETERING: The other thing that drives residual value is, what's the cost of alternatives? If electricity rates are going up, that's going to drive the residual value of the system, because the kilowatt hours it can produce are now worth more.

MR. MARTIN: Karen Morgan, is it reasonable to expect that you can tear panels off a parking structure and put them someplace else in 15 years?

MS. MORGAN: We have actually come up with removable solar trees so that we can move them around. However, the practical answer is I would think the current technologies would stay in place and you would install new technologies alongside them instead of ripping them out.

MR. MARTIN: Arno Harris, any actual experience taking used panels and putting them up someplace else?

MR. HARRIS: A previous business had a customer that ended up selling a building and deciding to move the system from one roof to another and, through that process, we got a pretty good sense of what it takes. With today's modular, non-penetrating mounting systems, there is nothing physically embedded in the roof structure and the process goes fairly quickly.

MR. BEEBE: We have an interesting residual value proof point, which is that last week thieves went up on a roof of one of our installations and duct taped about a dozen panels together and were repelling off the roof with expensive repelling gear with these panels as the police waited for them on the ground. That suggests there is a rather strong after market in used panels.

Technology Risk

MR. MARTIN: Paul Detering, there are lots of people in Silicon Valley tinkering in garages with new technologies. That suggests there is a fair amount of technology risk in this business. How does that affect residual value?

MR. DETERING: The technology risk associated with the facilities we are deploying today is fairly low, because we are using traditional polycrystalline panels and well understood inverter technology. The interesting thing is, as some of that stuff comes out of garages, how we work with them to be on the leading edge and not on the bleeding edge of that new technology.

MR. MARTIN: Jeff Wolfe, is there a technology risk in this business or do the customers, once they have the panels on the roof, remain happy with them for 15 years?

MR. WOLFE: They tend to be pretty happy. Once we get stuff deployed, it is there, we have a revenue stream, and everything is under contract, so there's not really technology risk. The only risk is potentially to the residual value. If all of a sudden people are giving away panels, then that decreases the value of the panels on the roof. It does not bring it to zero, because the panels on the roof are already installed and free panels are not. That said, nobody is predicting free panels. People are predicting the value will decline over time and scale and improvements bring cost savings.

MR. BEEBE: I entered the market six years ago, starting by running a tracking concentration company called Energy Innovations, and the product still has not changed. During that period, I watched hundreds of millions of dollars of venture money come into the space with the expressed goal of lowering the cost of PV. In fact, during that period, PV panel pricing actually went up. So I'm thinking there's an interesting venture-capital-invested-cost-change model that isn't that pleasant and that the biggest innovations, in terms of engineering, come from the financing side / *continued page 12*

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a separate tax credit for investing in affordable housing.

The US government offers anyone installing new equipment to generate electricity from sunlight a tax credit for 30% of the cost of the equipment, The credit is claimed in the year the equipment is placed in service. The 30% credit can be claimed only on commercial projects. A project that is owned by a solar company and used to supply electricity under contract to a homeowner or apartment building is considered commercial. The credit amount drops to 10% for projects placed in service after this year. However, Congress is expected to extend the deadline.

The tax credit is reduced to the extent the project is funded in part with tax-exempt bonds or "subsidized energy financing." An example of subsidized energy financing is a loan under a state or local government program aimed at encouraging energy conservation.

The IRS told a partnership that was set up to develop a low-income housing complex that it can claim the full 30% solar credit. The agency said no reduction is required despite the fact that the project is being financed with tax-exempt bonds. None of the bond proceeds will be used to pay for the solar equipment. The bond documents explicitly prohibit use of any bond proceeds to pay for the solar equipment, and the solar equipment is not included in the collateral for the bonds.

The advice was in a private ruling that the IRS made public in late May. It is Private Letter Ruling 200820011.

US UTILITIES that start reporting customer connection fees as income must treat the change as a "change in method of accounting," the IRS said.

That makes the change more costly.

US utilities usually charge new customers for electricity, gas, water, sewage, telephone and cable television service a "connection fee" to cover the cost of running a line or gas main to the customer's property. These fees must be reported as taxable income. / *continued page 13*

Solar Market

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because, over that same period of time, when we started selling PV systems, the thing that most shortened our time to close on a given sale is the power purchase model for financing systems, not the technology.

Coal-to-Liquids Projects in the United States

by Todd Alexander and Richard Susalka, in New York, and Jeff Kogan, in Moscow

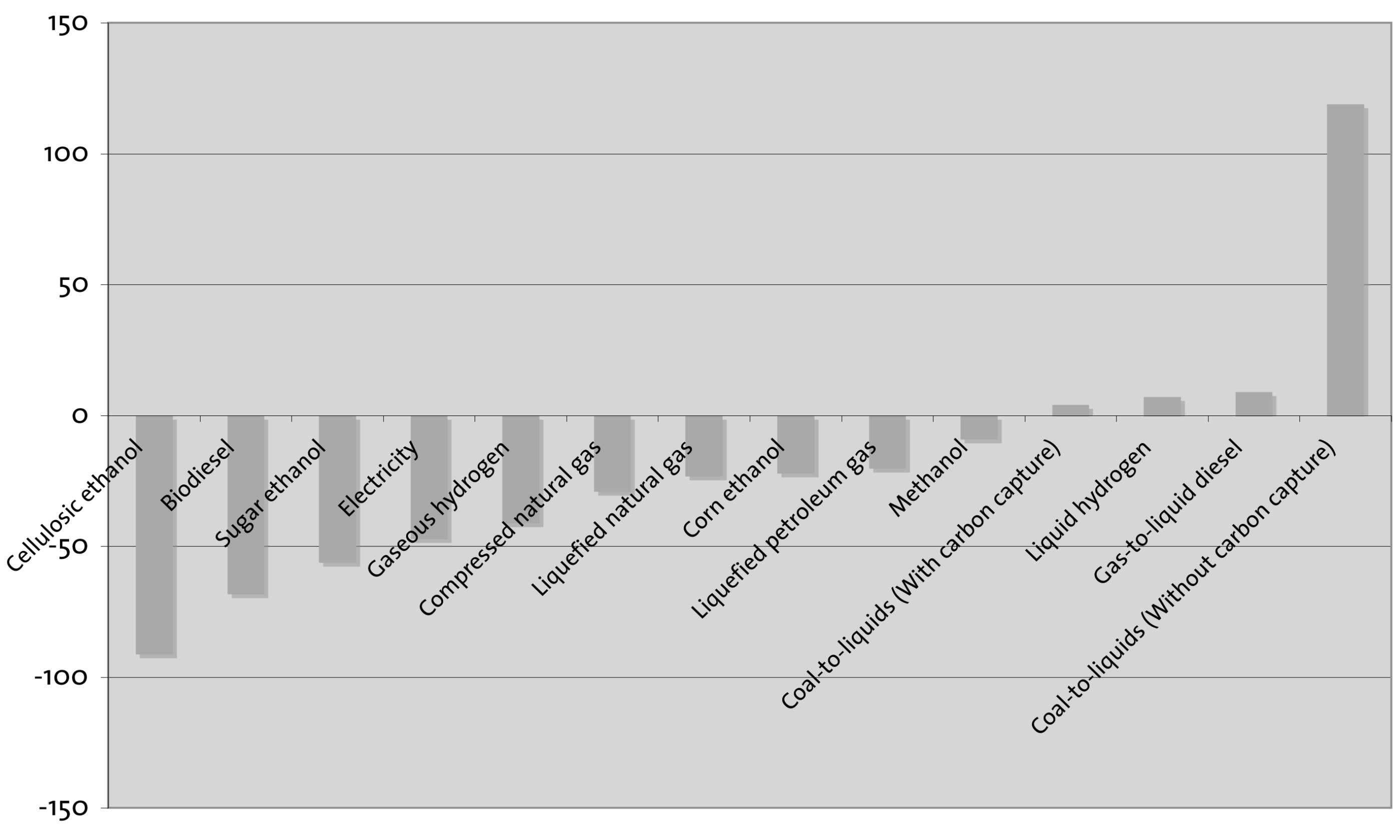
It is a challenge currently to construct plants in the United States to turn coal into transportation fuels, but the market is well on the way to solving the challenges. Several large coal-to-liquids plants are likely to be under construction by the end of the decade.

High oil prices and abundant coal reserves in the United States make such plants potentially-attractive investment opportunities. The United States has the largest known coal reserves in the world. The plants are profitable if oil prices remain at least at $45 to $55 a barrel.

Coal-to-liquids, or CTL, involves the conversion of coal to liquid fuels either directly or indirectly. Direct liquefaction is not yet commercially proven, but the indirect method, which involves an intermediate gasification stage followed by liquefaction, has a proven track record. The most common version of this technology is the Fischer-Tropsch process, which uses a catalyst such as iron or cobalt to turn synthesis gas made from coal into liquids.

The most widespread use of CTL technology is in South Africa, where an estimated 300,000 barrels of gasoline and diesel are produced every day. China is an emerging CTL player with a series of plants under development, and its first large-

Estimated Change in Greenhouse Gas Emissions with Petrol Replaced with Alternatives



Source: US Environmental Protection Agency scale CTL plant is scheduled to come on line in 2008. China's unconventional oil supply from coal-to-liquids plants is estimated to reach 750,000 barrels a day by 2030, according to the International Energy Agency.

In the US, there are several plants under development, including Rentech plants in Montana and Mississippi, a DKRW plant in Wyoming and a Baard Energy plant in Ohio. CTL enjoys considerable support from the United States Air Force, which has already begun certifying its fleet of aircraft for a blend using 50% CTL fuel and expects the entire fleet to be fully compatible with the blend by 2016. If current expectations hold true, the US military will being purchasing 400 million gallons of CTL fuels annually by 2016.

Challenges

The technology faces a variety of obstacles in the United States, the foremost of which is environmental. In many respects, fuel produced from CTL is cleaner than fuel from crude oil, because of inherent impurities found in crude oil, such as sulphur and nitrogen oxide, can be filtered from coal in the gasification process and in post-gasification treatment.

However, the CTL process produces relatively high carbon emissions. According to a recent study funded by the National Energy Technology Laboratory, the US Department of Energy and the US Air Force, the carbon dioxide emissions of CTL, on a well-to-wheels basis, are 1.8 times more than petroleum, due to the energy used in the conversion process and the high carbon content of the coal feedstock. The CO_2 issue is a significant political obstacle to widespread CTL development in the United States.

The large capital outlay required for a CTL project is another significant hurdle. To be efficient, CTL projects must produce upwards of 15,000 to 25,000 barrels a day, and the capital cost of such a project is measured in the billions of dollars.

In addition to the size, the complexity of CTL projects is a significant challenge when it comes to financing the projects. A typical indirect coal liquefaction plant requires the seamless integration of roughly seven separate functions, including not only the gasification technology and the liquefaction technology, but also often an on-site power plant. The perceived technology risk is not only the sum of the risks presented by each technological component, but also the risk that the components will not integrate harmoniously. Although a number of creditworthy contractors are */ continued page 14*

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Some utilities have been slow to do so.

Normally when a company changes the way it calculates its income, the change is considered a change in accounting method, meaning it requires prior approval from the IRS and the company must not only report future amounts correctly but also make an adjustment on account of having done things differently in the past. This is called a "section 481 adjustment." Ordinarily, the extra income tied to past-year reporting can be spread over four years.

The US Tax Court told Saline Sewer Co. in 1992 that it was not a change in accounting method when the utility started reporting customer connection fees as income. A federal district court in Florida told Florida Progress Corp., an electric utility, the same thing in 1999.

The IRS said in June that it disagrees.

Changing how a company calculates its income is a change in accounting method if it affects the timing of when income is reported, but not if it leads to a permanent increase or decrease in income. Thus, for example, it is a change in accounting method for a company to change how it depreciates assets. It is not such a change to switch to reporting certain payments to shareholders as dividends rather than interest.

The IRS said that a utility that starts reporting customer connection fees as income is merely changing the timing of its income and not the absolute amount. The utility would have reported no income before the change and it could not depreciate the line or gas main on the customer's property because the customer paid the cost; the utility paid nothing for it. The IRS said the *net* income of the utility after the change is still zero. That's because it has income but it can also deduct the amount as depreciation over the life of the line or gas main that was installed to connect the customer.

This is a little too metaphysical. It is hard to see how there is a change in the timing of income when the amount was zero both before and after. The utility will pay more in taxes after the change; */ continued page 15*

CTL Projects

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active in this area, these contractors are reluctant to bear full responsibility for these risks and, as a result, significant guarantees of overall performance and schedule are not yet available.

Because of the size and complexity of CTL plants, full commercial operations may not commence until five years after the start of construction. As a result, projects that use debt financing are likely to incur significant interest expense during construction. This not only increases the overall project cost, but also reduces the attractiveness of bond and term loan B-type financing structures, which customarily require the borrower to draw down all or a significant portion of the funds available under the credit facility at financial closing.

Developers of CTL projects must also contend with commodity risk. Although the volatility of the oil market is a challenge to all forms of alternative fuels, this challenge is greater in the CTL context given the length of the construction and ramp-up phases for a CTL plant. The use of coal also means there is commodity risk because the price of coal is not highly correlated with the price of synthetic fuel.

Overcoming the Challenges

The early developers of CTL projects in the United States have begun tackling the challenges. Thus far, developers have proposed to address the CO_2 issue primarily by sequestering CO_2 in the gasification stage and disposing of it through enhanced oil recovery. There are several enhanced oil recovery operations currently in the US, several of which already accept CO_2 by pipeline. However, the capacity of these operations to accept CO_2 is limited, and CTL will compete with other suppliers of CO_2, including coal-fired power plants. In addition, carbon sequestration will not truly take off in the United States without construction of a network of CO_2 pipelines that mirrors the existing network of natural gas pipelines and without further development of the laws governing underground storage of carbon emissions.

Promising studies have shown that the carbon emissions of a CTL project can be reduced beyond that of a conventional petroleum refinery by co-gasifying a modest amount of biomass with coal. According to a study funded by the three US government agencies mentioned earlier, a 20% reduction in carbon emissions can be achieved through CTL (as compared to the production of low-sulphur fuel from an existing conventional petroleum refinery) by co-processing coal with 10 to 18% (by weight) of biomass, such as switchgrass, poplar trees and corn stalks.

Several large coal-to-liquids plants are likely to be under construction in the United States by the end of the decade.

It is too early to provide a meaningful opinion on whether CTL projects will be able to pass on the costs of complying with any carbon controls in the United States. The US is still debating what form such controls will take. They are not expected to be enacted until after the next President takes office.

The high capital costs of these projects can be partially mitigated through proper tax structuring. The US government offers as many as six subsidies that will pay anywhere from 30% to 55% of the capital costs of CTL projects. First, depreciation can account for anywhere from 17¢ to 30¢ per dollar of capital cost. Second, developers may be able to deduct 50% of the cost of the Fischer-Tropsch liquids train immediately in the year the plant is placed in service, which accounts for another 2.6¢ per dollar of capital cost. This deduction is only available in cases where the developer signed a binding contract by December 2007 with a construction contractor to build the liquids train. Third, there is a refined coal credit of $5.88 per ton that is available to developers that convert coal into a gaseous, liquid or synthetic fuel that will be resold for the purposes of making steam. Fourth, there is also a potential 20% investment credit that could be applied towards the gasification component of the plant. Fifth, transportation fuels collected through the Fischer-Tropsch process can qualify for an excise tax credit of 50¢ a gallon. This credit can only be claimed through September 30, 2009 on output, although it is likely to be extended by Congress. Sixth, and finally, CTL projects can take advantage of a government inducement to encourage Americans to manufacture at home. Currently, 6% of the income of domestic manufacturers is not subject to federal tax and starting in 2010, the incentive will be increased to 9%.

Although few developers have the income to take full advantage of these tax benefits, developers can use structures, such as a sale-and-leaseback or partnership flip structure, to convert the tax subsidies into cash.

The technology and completion risks in CTL projects are expected to diminish dramatically as the United States market becomes more familiar with CTL technology. In the interim, and in the absence of creditworthy contractors willing to offer guarantees of performance and schedule on a complete facility, these risks must be built into the project as a contingency fee. Although such fees can become prohibitively expensive, they can be significantly reduced by obtaining guarantees for the individual components that make up the plant, such as the gasifier, the air separation unit and the Fischer-Tropsch unit. The remaining risks — integration, cost overrun, labor coordination and the like — can be addressed through additional contingency. A number of creditworthy contractors, who may be able to provide such guarantees, are active in this area.

The commodity risk tied to oil can be addressed through a variety of approaches. One strategy is to enter into futures contracts based on the price of diesel. This would make a portion of a project revenue stream more predictable, but this strategy tends to be prohibitively expensive in volatile markets, such as the diesel market, if implemented over a long term.

Another strategy is to enter into long-term fixed-price contracts for at least a portion of the facility's output, similar to those used in the ethanol and biodiesel industries. This approach has the benefit of providing a more predictable revenue stream, but would probably require the owners of the project to forego much of the upside potential of the project. Although the US Department of / continued page 16

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this is consistent with its having more income to report in time value terms. The IRS explained its position in Revenue Ruling 2008-30.

LUXEMBOURG announced a reduction in the corporate income tax rate from 29.63% to 25.5% and abolition of a capital duty. The changes are to take effect on January 1, 2009.

The capital duty is currently 0.5%. It is like a toll on money flowing through Luxembourg companies to reinvest outside. It would apply, for example, where a US parent company makes a capital contribution to a Luxembourg holding company that the holding company uses, in turn, to invest in a project in a third country.

The moves are an effort to keep Luxembourg competitive with Holland, Ireland and other jurisdictions that are making a play for offshore holding companies.

THE SALE OF A US BUSINESS may trigger a tax in more than one US state or in just the state where the US parent company is located under a US Supreme Court decision in April.

MeadWestvaco Corp. sold its Lexis-Nexis data research service in 1994 for $1.5 billion. It had a $1 billion gain on the sale. The business was organized as a division rather than a separate subsidiary. Lexis-Nexis is like Google for lawyers; it is a search engine for legal research.

Lexis-Nexis was headquartered in Illinois. The parent company, MeadWestvaco, has its headquarters in Ohio. Illinois insisted that the company had to pay taxes in Illinois on the gain from the sale.

Illinois distinguishes between "business income" and "nonbusiness income." The former is income from "transactions and activity in the regular course" of the taxpayer's business.

If the gain was nonbusiness income, then Illinois would allocate it entirely to Ohio where the parent company that received the income is based. None of it would be taxed in Illinois. However, if the gain was / continued page 17

CTL Projects

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Defense would appear to be a prime candidate for these types of contracts given the projected need of the Air Force for synthetic diesel and jet fuel, the value of this opportunity is limited by restrictions that limit the ability of the US military to enter into binding agreements with terms in excess of five years.

A third method is to capitalize on the flexibility of the CTL process by designing the facility to produce co-products for which long-term fixed-price offtake contracts are available.

The project might benefit by having the offtakers prepay for the output. The prepayments can be structured so that they are economically a type of soft debt that the developer can use to pay part of the capital cost of the project and repay by delivering fuel in kind. It is "soft" debt because it would not have the same default triggers as more traditional bank debt. Under US tax rules, the project may be able to delay reporting the prepayment as income and report it ratably over the contract term as the prepaid fuel is delivered.

With respect to coal, CTL developers could ensure the availability of predictably-priced coal by purchasing a coal mine or entering into long-term coal supply contracts at a fixed price or with a cap. A similar approach was taken by the independent power industry to resolve the lack of correlation between the price of natural gas and electricity.

As with any new type of project, it is just a matter of time before a financing template will eventually develop along with a "market" approach to tackling the various risks.

Securitizations of Tax Revenues in Mexico

by Boris Otto and José Antonio Chávez, in Mexico City

State and municipal governments in Mexico have been securitizing, or borrowing against, future tax collections as a way of raising needed funds to pay for infrastructure projects and to refinance prior public debt.

In the largest such transaction done to date using state taxes, the state of Veracruz converted its future payroll tax collections in 2003 into 6.3 billion pesos. The peso traded at .097¢ to the US dollar in early June. The securitization covered 30 years of future tax collections.

At least 40 such state and municipal tax securitization transactions have been done to date after the first one in 2002. The securitized taxes are generally revenue sharing payments to states out of federal tax collections by the central government. However, securitizations of state taxes such as payroll taxes and vehicle ownership taxes are being securitized more often in the last couple of years. The typical transaction raises between one and three billion in pesos. The typical use of funds is state infrastructure projects. The counterparties in the transactions are Mexican institutional investors.

Background

Under Mexican law, state and municipal governments are limited in their ability to raise tax revenue. States and municipalities do not have the option, as they do in the United States, of funding roads, schools and other infrastructure projects by borrowing at reduced rates in a tax-exempt bond market. Therefore, many turn to securitizations of the taxes they are allowed to collect.

Securitizations are only possible in states and municipalities that have the right legal framework. One of the first steps for the investment bankers and lawyers who are behind the transactions is to persuade the local Congress to put in place the right legal underpinning for a deal. The law must allow the state or municipality to assign the right to future tax revenue to a sole-purpose private trust that will receive the revenue and pay amounts due on securities. Any provision allowing administrative control by the state or local government must be avoided. The trustee is an authorized Mexican bank and is appointed by the bondholders.

Basic Structure

In the typical transaction, the state or municipality first requests authorization from the local Congress to carry out the intended securitization.

A trust is formed. The government assigns the right to 20 to 30 years of tax revenue to the trust. The government commits to the trust to collect the revenues and not to change the tax rate. No commitment is made about the amount of tax collections.

The state or municipality issues debt securities, called *certificados bursátiles,* through the trust. The bondholders have no recourse against the state or municipality; the trust is the only obligor. The revenue collected is used by the trust to repay the securities. The securities are placed on the Mexican Stock Exchange, called the *Bolsa Mexicana de Valores*. Only Mexicans are allowed to acquire such securities directly from the Mexican Stock Exchange. However, there are legal structures that make it possible for foreigners to acquire the securities, for example, by using a special-purpose Mexican company to acquire the bonds and then issue US bonds collateralized by the Mexican bonds. The US bonds used in such structures are not very liquid; there is no secondary market for them.

The typical security is a debt instrument with a term of 20 to 30 years and that bears floating interest at a market rate. The average rate for such securities is currently 9%. There is usually only one tranche of securities issued with a single maturity date.

The government assigns only a percentage of the expected tax collections. Securitizations are done typically at a 50% level of expected tax collections to address the risk that tax revenue might vary.

If tax collections fall short of what is required in any period to pay debt service, then the bonds become subject to cash sweeps until the bonds have been repaid in full.

The main risks for the holders of the securities are the risk that tax collections might fall short of what is expected due either to an economic downturn or inability of the government to collect fully from taxpayers and the risk that the government might decide to abolish the tax. There is nothing to prevent the state as a sovereign entity from abolishing the tax, but it would have to pay damages to the bondholders. The debt would be accelerated, and the bondholders would have recourse against the state. The indemnities in such deals have a wide scope; in general, the state must indemnify for all harm caused by its actions.

The securities are rated by Standard & Poor's, Moody's and Fitch Ratings. The key to getting an investment-grade rating is the legal strength of the structure and the level of collateral.

There are a number of recurring legal issues that come up in deals.

One of the biggest issues is isolation of the funds derived from securitized taxes from the control of the state or municipal government. This is done by requesting the taxpayers to pay the relevant taxes directly to a bank account owned by the trust. So far there have not been any / continued page 18

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business income, then the state would treat part of it as earned in Illinois.

The US constitution places limits on the ability of a state to tax companies. A company must have a sufficient link to the state to justify a tax. In today's economy where large conglomerates of affiliated companies operate across many states, each state ends up apportioning the income of the entire group, including subsidiaries, partly to the state under a formula. Most states use some combination of property, payroll and sales in the state as a percentage of total property, payroll and sales of the larger "unitary business" — or conglomerate — to apportion income. States moved to this approach after the rise of railroad, telegraph and other multistate businesses made it too hard to trace actual dollars to the state. State tax departments are also too small and no match for the complicated internal accounting of large multinational corporations.

MeadWestvaco argued that the gain from the sale of Lexis-Nexis was nonbusiness income that should be taxed only in Ohio. It also argued that Lexis-Nexis was not part of a larger unitary business with the parent since it operated as a standalone company with its own management team and with oversight by the parent, but no involvement by the parent or headquarters staff in its day-to-day affairs.

The Illinois courts concluded that Lexis-Nexis was separate enough that it was not part of a unitary business, but nevertheless said the state could apportion part of the gain to Illinois because Lexis-Nexis served an "operational purpose" in the larger company. It was considered in the strategic planning and allocations of resources by the parent company.

The US Supreme Court added its two cents in April.

The court said two things and then sent the case back to Illinois for the Illinois courts to reconsider.

First, either the business sold is part of a unitary business or it is not. / continued page 19

Mexico

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legal challenges to isolation, nor have any states or municipalities ignored their obligations. Each state and or local government has its own mechanism for collecting taxes.

Another challenge is to persuade the local Congress to authorize the transaction. There is a strong prejudice in Mexico against public debt; there has been too much experience with local officials who overborrowed to finance political campaigns and pay for projects that did not perform as expected. Nevertheless, local Congresses continue to approve these transactions because most states have few other options for financing needed infrastructure. The holders of the securities bear the risk that tax collections will fall short. ◎

Mexican states are borrowing against future tax collections in order to fund infrastructure projects. The average deal raises one to three billion pesos.

Calculating How Much Tax Equity Can Be Raised

by Keith Martin, in Washington

Many developers of renewable energy projects in the United States are struggling to model their projects correctly so that they can calculate how much tax equity can be raised to help pay the project cost.

This requires including four blocks of figures in the computer model.

A developer can raise an amount of tax equity equal to the present value of four items discounted at the target internal rate of return required by the tax equity investor. The four items are the tax credits the tax equity investor will receive, the cash it will receive, its anticipated tax savings from depreciation and any interest deductions, less the taxes it will have to pay on its share of taxable income from the project.

Target returns in the US tax equity market had dipped below 6% unleveraged and after taxes. They are headed back up and are currently in the mid-6% to low 7% range for one-off wind and solar photovoltaic projects. They are lowest for portfolios of projects where there is risk diversification across geography and by equipment type. They are 200 to 250 basis points higher in deals where there is project-level debt as the equity will require a premium against the risk that it will squeezed out of the deal before its target return is reached.

Background

The chief financial officer of a renewable energy company must cover the capital cost of his or her project through a combination of true equity, tax equity and debt.

The US government pays as much as 63% of the capital cost of a typical wind farm and 56% of the cost of a solar project through tax subsidies.

Few developers are in a position to use the subsidies because of inadequate tax base.

The most common way to get value for them is through a "partnership flip" transaction. The developer brings in an institutional equity investor to own the project as a partner with the developer. The investor puts up a share of the capital for the project and is allocated 99% of the economic returns until it reaches a target internal rate of return, after which its interest drops usually to 5%, and the developer has an option to buy out the investor's remaining interest for fair market value determined at the time. Cash may be distributed 100% to the developer until it gets back the capital it has in the deal, after which cash is distributed 99% to the investor until the flip.

In solar deals, the tax benefits might be transferred instead by selling the project to the institutional investor and leasing it back.

Lease structures do not work for wind farms and geothermal projects. They work in theory for biomass projects, but any lease would be an "inverted" lease where the investor is the lessee and the developer is the lessor.

The Internal Revenue Service issued guidelines for partnership flip structures in October 2007. The agency said it is okay with the structure, but that anyone straying outside the guidelines should expect to be subjected to "close scrutiny" on audit. The guidelines were addressed to partnership flip deals involving wind farms. However, the market has followed them in other types of projects.

At most, 99% of the tax subsidies can be transferred to an investor in a partnership flip deal.

In practice, the percentage may be smaller.

Any tax subsidies that cannot be transferred to the investor can be carried forward by the developer for up to 20 years.

Each partner in a partnership flip transaction must track its "capital account" and "outside basis." These are different ways of measuring what each partner invested and took out of the deal. If either measure goes negative, then it is a sign that the partner took out more than his fair share. They are also a limit on the capacity of the investor to absorb tax benefits. Consequently, it is important to model both accurately.

Capital Accounts

A partner's capital account starts with the cash he or she paid to buy into the deal or contributed to the partnership. It also includes the fair market value of any property contributed.

There are two forms of partnership flip deals.

In deals with larger developers who build projects on their own balance sheets, the investor usually pays a purchase price to the developer directly to buy an interest in a limited liability company that owns the project. This is called the "purchase model." The investor usually waits to buy into the deal after it is already in service, except in solar deals where the investor will not be able to claim a 30% investment tax credit on the project unless he is a part owner before the project is in service.

In deals with smaller developers who must borrow from a construction lender to build a project, the / *continued page 20*

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If it is not part of a unitary business, then none of the income can be apportioned to Illinois. However, the fact that an asset serves an "operational as opposed to purely an investment function" can make it part of a unitary business. Thus, for example, a state like Illinois can tax a share of interest earned on a bank account that the parent company in Ohio has in a third state if the bank deposit is part of the working capital of the larger unitary business. Second, in order for two companies or divisions to be linked together in a unitary business, they must have "functional integration, centralized management, and economies of scale." The trial court in Illinois said Lexis-Nexis and the Ohio parent company had none of these things. The state appeals court failed to address the question.

The case is *MeadWestvaco Corp. v. Illinois.*

COAL COMPANIES must pay US excise taxes on coal sold for export if the coal makes an intermediate stop at a processing plant for conversion into synfuel.

If the coal were exported directly, it would not be taxed. The US government collects excise taxes of $1.10 a ton on coal from underground mines and 55¢ a ton on coal from surface mines. The taxes are paid by the producer and are collected at time of sale. However, the US constitution bars taxes on exports. The IRS conceded in a notice in 2000 that the taxes are not owed on coal sold for export after losing a test case on the issue in a federal district court in Virginia the year before.

To avoid a tax, the coal must be "in the stream of export" when it is sold and it must actually be exported.

The United States used to reward anyone converting coal into a synthetic fuel with tax credits tied to the quantity of synfuel produced measured in mmBtus. In the mid-1990's, 53 small plants were built that used chemicals to turn coal into synfuel. The processing caused almost no change in the physical appearance of the coal, but there was enough change / *continued page 21*

Tax Equity

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investor commits at the start of construction to make a capital contribution at the end of construction in exchange for an interest in the project company. This is called the "capital contribution model." The project company uses the capital contribution from the investor to pay down the construction debt.

In either case, the investor takes an opening "capital account" equal to what he pays the developer or contributes to the project company to buy into the deal.

The project company does not exist for tax purposes until the investor funds. Until then, it is usually a limited liability company with only one owner: the developer. Such companies are "disregarded" for tax purposes until they have at least two owners.

When the investor funds, the project company turns into a partnership for tax purposes. In the purchase model, the investor is treated as having purchased an undivided interest — or percentage of — the completed project from the developer and contributing it to a new partnership with the developer. The developer contributes the share of the project he retained. In the capital contribution model, the investor is treated as having made a capital contribution to a new partnership in exchange for an interest. The developer is treated as if he contributed the entire project.

In both models, the investor has an opening capital account equal to his cash payment.

In the purchase model, the *developer* has an opening capital account equal to the fair market value of the share of the project it retained. In order to calculate that, set up a fraction. The numerator is the amount paid by the investor. The denominator is the fair market value of the entire project. In most deals, the fair market value of the entire project is determined by a desktop appraisal at closing using discounted cash flows. The fraction is the share of the project the investor purchased; the developer retained one minus that fraction.

In the capital contribution model, the developer has an opening capital account equal to the fair market value of the entire project. However, he must subtract the opening capital account of the investor plus the amount of any term debt that will remain outstanding at the end of construction. By subtracting these amounts, the developer ends up with an opening capital account equal to the equity value he has in the project. His opening capital account is the claim he would have on the project assets if the partnership were to liquidate the next day. The lender would have a claim for the outstanding debt. The investor would have a claim for the capital the investor contributed. The developer has a claim for what is left.

The US government pays as much as 63% of the capital cost of a typical wind farm and 56% of the cost of a solar project through tax subsidies.

Capital accounts are a fluid concept. They go up and down each year to reflect partnership results.

Add to each partner's capital account at year end his share of income earned by the partnership. Subtract the losses he is allocated and cash he is distributed. In other words, increase the capital account each year as the partner suffers detriment; having to report income is a detriment (because taxes will have to be paid on that income). Reduce the capital account by the benefits the partner receives; being distributed cash or allocated losses is a benefit.

The income and loss that are reflected in capital accounts are "book" income and loss.

The "book" amounts are not the same as what is reported on financial statements. They are not the taxable income and loss that get reported on tax returns, either.

Rather, they are the income or loss computed at the partnership level the same way as the taxable income the partnership reports to the IRS, except that the project is depreciated by starting with its fair market value when the investor funds (and the partnership is formed) rather than the actual cost of the project. Otherwise, the depreciation is calculated the same way as tax depreciation. Thus, the only difference between "book" income and taxable income is the depreciation used to calculate book income may be a higher amount; it starts with the fair market value of the project rather than its cost.

A partner's capital account serves two purposes.

First, it is the claim the partner will have on the assets in the partnership if the partnership liquidates.

Second, it is a limit on the amount of losses the partner can be allocated. A partner's capital account cannot go into deficit unless the partner is willing to contribute additional capital to the partnership when the partnership liquidates.

Most investors in the tax equity market are willing to step up to such a "deficit restoration obligation"; however, they will agree only to contribute up to a fixed dollar amount. The dollar amount is the amount of deficit that the computer model suggests will reverse itself on its own under reasonably conservative assumptions about how the project will perform. For example, in wind farms and geothermal projects, the tax benefits are largely exhausted after 10 years. After that, the partners receive both cash and taxable income. If the income to be reported exceeds the cash — for example, because cash must be used to repay long-term debt — then the partners will have "phantom" income to report from the partnership. For example, a partnership might earn $100 from electricity sales, but have to use $80 to repay debt principal; the partners must still report the full $100 in income even though they are distributed only $20 in cash. The amount of this phantom income will increase their capital accounts. An investor will usually step up to a deficit restoration obligation in the amount of the aggregate phantom income expected over the remaining life of the project.

A rough rule of thumb used to be that tax equity covered 65% of the capital cost of a wind farm. The percentage has dropped recently to closer to 50%. This is due to increasing turbine costs; most turbines are priced in euros, and the euro has gained ground against the dollar. At the same time, the output of the project does not change, so the cash and tax credits on electricity output do not change, meaning the cost of projects has increased but without a */ continued page 22*

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in the chemical composition for it to qualify as synfuel.

The IRS said in a "technical advice memorandum" made public in May that any coal company selling coal to such a plant and then repurchasing the coal for export could not avoid the US excise taxes on coal since the coal was never exported.

What the company ended up exporting was a different product: synfuel. The technical advice memorandum is a ruling by the IRS national office to settle a dispute arising from a tax audit of the coal company. The ruling is Technical Advice Memorandum 200820035.

MINOR MEMOS. The IRS is under pressure to relax the rule that electricity from US wind farms and geothermal and biomass power plants must be sold to an "unrelated person" in order for the plant owners to claim production tax credits of 2.1¢ a kilowatt hour. (The credits are 1¢ a kWh in the case of biomass plants.) Six members of the House tax-writing committee wrote the Treasury Department a letter in late April asking the government to relax the rule. The letter writers want the credits to be allowed in a case where a utility owns a power plant in partnership with a developer and the utility buys all the electricity. Under current rules, the utility is considered related to the partnership if it provides more than half the capital for the project or is allocated more than half the income . . . . Some accounting firms have been encouraging companies that receive tax incentives in the form of property or income tax abatements or rate reductions, as an inducement to relocate and bring jobs, to claim tax deductions for state or local taxes paid as if the companies had paid the full taxes at statutory rates. The accounting firms claim that the incentives must be reported as income, but the income can then be excluded under a special rule in section 118 of the US tax code that lets corporations avoid reporting "nonshareholder contribu- */ continued page 23*

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commensurate increase in the amount the tax equity is willing to pay.

Another way to deal with deficit capital accounts is to pay part of the cost of the project with debt at the project level. IRS rules allow capital accounts to go into deficit to the extent they are driven into deficit by depreciation claimed against the share of project cost funded with nonrecourse debt. Thus, for example, suppose a project costs $100 and the cost is paid with $40 in equity from the partners and $60 in nonrecourse debt. The first $40 in "equity" depreciation will usually have to be shared in the same ratio the partners contributed equity, but the last $60 in "nonrecourse" depreciation can be shared in any ratio the partners wish, as long as the ratio is consistent with some "other significant item," like the 99-1 ratio used to allocate other partnership items. (This is an oversimplification; it is discussed in more detail later.) The reason the nonrecourse depreciation can be shared 99-1 in favor of the investor is that US tax rules require the partners to report the later phantom income tied to repayment of the nonrecourse debt principal in the same 99-1 ratio. In other words, any deficit created by the nonrecourse deductions will reverse itself because it will be matched by future phantom income.

After calculating the capital accounts, the computer model should show the balance at year end in each partner's capital account.

It should then have another line adding back the "nonrecourse" depreciation the partner was allocated. The next line should show the balance in the "adjusted capital account." It is the adjusted capital account that cannot go into deficit unless the partner has agreed to a deficit restoration obligation.

If a partner has a deficit in his adjusted capital account that exceeds the deficit he has agreed to restore, then the standard partnership agreement shifts any losses he was allocated that year to the other partners to prevent a deficit.

There is a common misconception in the market that investors are able to absorb the tax subsidies fully from a project simply by stepping up to a large enough deficit restoration obligation. Stepping up to such an obligation may prevent losses from being shifted to another partner, but it does not ensure the investor will be able to use the losses fully. Even if he can keep the losses, his use of them may be suspended if he does not have enough "outside basis" to absorb them fully. Outside basis is the next block of figures that it is important to calculate.

If losses shift in a year because of inadequate capital account, then most tax counsel take the position that the shift will drag production tax credits with it. The US government allows production tax credits of 2.1¢ a kilowatt hour to be claimed on electricity from wind farms and geothermal projects for 10 years after the project is placed in service. Credits of 1¢ a kilowatt hour can be claimed on the electricity from a biomass project for 10 years. The credits must be shared by partners in the same ratio they share in "receipts" from electricity sales. The IRS has not said how to determine in what ratio "receipts" are shared; receipts are not the same thing as cash. Most tax counsel assume receipts are shared in the same ratio as net income and loss for the year. Thus, if net losses are supposed to be shared in a 99-1 ratio in favor of the investor, but the investor has too little capital account in a year to absorb the full net loss in that ratio with the result that part of the loss shifts back to the developer, the production tax credits will end up being allocated that year in the actual ratio that losses were shared.

The amount of financing that a project can raise against these tax benefits is calculated by discounting four items at the target yield a tax equity investor will require.

Outside Basis

A partner's outside basis is another potential limit on the ability of an investor to absorb tax subsidies. It is the same thing as his capital account, with three exceptions.

The investor's opening outside basis is the same as his opening capital account — what the investor paid or contributed to the partnership — but the *developer's* outside basis is his "basis" or cost of the share of the project he is treated as having contributed. Thus, in the purchase model, take the fraction of the project that the developer is viewed as having retained. Multiply the cost of the entire project by that fraction. The developer's outside basis is that fraction times the original project cost. In the capital contribution model, the developer's outside basis is the cost of the entire project, less the capital contributed by the investor and less the amount of term debt.

Outside basis goes up and down each year in the same way as capital accounts. Add income. Subtract cash distributions and losses allocated to the partner. However, instead of using the "book" income and loss, use taxable income and loss.

Finally, a partner's outside basis includes not only what he contributed to the partnership, but also his share of any debt at the partnership level. Put differently, his capital account is just his equity in the deal. His outside basis is his equity plus his share of debt at the partnership level.

Each partner includes a share of partnership- or project-level debt in outside basis by working down a three-level waterfall. The model should recalculate the amount of debt in each partner's outside basis at the end of each year. It should have a line showing the outstanding principal amount of the term debt there is to put in partners' outside bases. Then give each partner first an amount of debt equal to the nonrecourse deductions he has been allocated to date and that have not been charged back. (How to calculate this is discussed below.) Next, give the developer an amount of debt equal to the "built-in gain" or appreciation there was in the share of the project he was treated as contributing when the partnership was formed. The built-in gain gets worked off over time, so the amount to put in the developer's outside basis on account of built-in gain reduces gradually over time. (The concept of built-in gain is discussed later in the article.) Finally, the remaining debt is shared by partners in the same ratio that income is allocated (*i.e.*, 99-1 initially in favor of the investor and then usually 5-95 after the flip).

If one of the partners or one of its affiliates makes a loan, then that debt must go entirely into its */ continued page 24*

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tions to capital" as income. The argument is that since the amounts were income — absent this exclusion — they can be deducted as taxes paid. The IRS put out a "coordinated issues paper" to its agents in the field in late May to flag the scheme. The IRS said the tax abatements are not income. The paper is LMSB-04-0408-023.

— contributed by Keith Martin and John Marciano in Washington.

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outside basis, and any depreciation tied to such a loan must also be allocated entirely to that partner.

The model should show each partner's outside basis at year end.

Then it should have two more lines.

If the outside basis is negative, then the model should treat the cash the partner was distributed that year — to the extent needed to get the outside basis back to zero — as an "excess cash distribution," meaning the partner must report it as capital gain. It is inefficient to be in such a position, since the partners will have already had to have reported the income in full that the partnership earned from electricity sales. When cash is later distributed to partners, it is not normally taxed again. An excess cash distribution is a form of double taxation.

If the partner still has a negative outside basis after converting all of the cash he was distributed into an excess cash distribution, then the model should suspend the use of any losses the partner was allocated that year to close the remaining gap. The partner keeps the losses, but he cannot use them until a later year when his outside basis goes back up.

If there is an excess cash distribution, then the model should increase the "inside basis" — or basis that the partnership has in the project — by the amount of the excess cash distribution. The partners' capital accounts should also be increased by the same amount. However, the investor's capital account will usually increase by 99% of the excess cash distribution if it occurs before the flip, and the developer's capital account will increase by only 1% of it. The increase must bump up partner capital accounts in the same ratio that a gain in the same amount would have been reported by the partners.

It is important in deals where the term debt will remain outstanding after the flip in the investor's interest to check whether the flip will cause an "excess cash distribution" to the investor. When the flip occurs, the investor's share of partnership income will drop from 99% to around 5%. This will lead potentially to a large amount of debt being shifted from the investor's outside basis to the outside basis of the developer. The mechanism by which this shift occurs is the investor is treated as if he was distributed an amount in cash equal to the debt that shifts. If this "deemed" cash distribution exceeds his remaining outside basis at the time, then he will have an excess cash distribution that must be reported as capital gain.

Current tax equity yields for one-off wind and solar photovoltaic projects are in the mid-6% to low 7% range.

In some deals, the investor's interests flips down to 5% in two stages to try to manage this problem. The first flip is to an intermediate sharing ratio that avoids such a deemed distribution.

Minimum Gain Chargebacks

"Minimum gain" is a fancy term for a simple concept. The model will need another block of figures to track minimum gain. The concept is as follows.

Suppose two partners form a partnership. The partnership builds a project at a cost of $100. It pays the cost with $40 in equity contributed by the partners and $60 in nonrecourse debt borrowed from a bank. The partnership will have $100 in depreciation. However, the partners are really only exposed to $40 in loss in value in the project, because they can always walk away and hand the keys to the nonrecourse lender. It is the bank that is exposed to the last $60 in depreciation; depreciation represents erosion in value of the project.

As a general rules, partners are only supposed to claim losses that they really suffer.

However, the IRS will let the partners claim the full $100 in depreciation in this case on one condition: they must agree to report the "phantom" income when the debt is repaid in the same ratio they claim the "nonrecourse" depreciation tied to the loan.

Therefore, in any deal where there will be term debt, the model must track the amount of "nonrecourse" depreciation and how it was allocated to the partners.

This is simple enough to do. There should be a line showing the outstanding debt principal. Next, a line should show the inside basis, or unrecovered "book" basis that the partnership has in the project. There is no "minimum gain" until the inside basis in the project drops below the remaining debt principal. At that point, the lender is exposed in theory to a loss if the project company walks away from the project and hands the lender the keys. The shortfall, or potential loss, is the "minimum gain."

At each year end in which the minimum gain increased, the amount of the increase is the amount of book depreciation the partners were allocated that year that is considered nonrecourse depreciation, or depreciation that reflected an erosion in value to which the lender is exposed. In the first year in which the gap starts to narrow, the partnership must "charge back" income to the partners in the amount of the decrease. This income must be reported by the partners in the same ratio they were allocated the nonrecourse deductions earlier. These chargebacks are not additional income. They are simply a direction that the first amount of income that year must be shared by partners in the same 99-1 or other ratio that they were allocated the nonrecourse depreciation earlier. The remaining income for the year is allocated according to the business deal.

The point is that in any deal where term debt will remain outstanding after the flip, the investor will be allocated phantom income as the debt principal is repaid in a 99-1 ratio. It will be allocated income in that ratio at a time — after the flip — when it is being distributed only 5% of the cash.

This will take the investor's return backwards.

Investors in such situations insist on one of at least two fixes. One is the investor might insist on being distributed enough cash to cover his taxes. He will also need additional income to restore his capital account. (Cash distributions reduce his capital account; income pushes it back up.) It is an iterative calculation to figure how much additional cash and income the investor needs to remain whole.

Alternatively, the investor might only credit the time value of the nonrecourse depreciation in determining when he reaches his target return (rather than treat each dollar of depreciation as saving him 35¢ in taxes). It should be possible to calculate when the depreciation will reverse due to chargebacks.

Built-In Gain

There is one more concept that must be reflected in the model in order for it to work properly. It is called "section 704(c) adjustments." Once again, the concept is simple.

Suppose two partners form a 50-50 partnership. The deal is that each must contribute $100. Partner A contributes $100 in cash. B contributes an asset worth $100 but that has been fully depreciated. This is not a fair deal for A, since the partnership will have a gain of $100 one day when it sells the asset that B contributed, and A will have to pay taxes on 50% of that gain.

Section 704(c) of the US tax code addresses this by requiring B to pay taxes on the full $100 in gain when the asset is sold. However, it also requires B to try to make it up to A in the meantime without waiting for the asset to be sold. B makes it up to A by shifting depreciation to which B would otherwise be entitled to A until A has received $50 in deductions.

In many partnership flip deals, the developer is viewed as contributing appreciated assets, and there is not enough depreciation to shift to make A, the investor, whole.

There are three ways to make section 704(c) adjustments. Under the "traditional" method, the partnership allocates A the full amount of tax depreciation each year up to the "book" depreciation that A was allocated. For example, suppose the partnership has $20 in book depreciation, but only $15 in tax depreciation in a year, and the business deal is the investor gets 99% of everything until the flip. The investor gets 99% of the book depreciation, or 99% x $20 = $19.80. The investor also gets all $15 in tax depreciation. Since there is not enough tax depreciation to shift, when the partnership sells the project or liquidates, any remaining built-in gain that was not worked off by shifting tax depreciation will have to be allocated to the developer.

The traditional method is common in the purchase model where the investor buys an interest in the deal by making a payment directly to the developer. In the contribution model, the "remedial method" is more common. Under the remedial method, the investor gets an amount in tax losses equal to the "book" depreciation he is allocated. If there is not enough tax depreciation, the investor still claims a / continued page 26

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tax loss equal to its book loss, and the developer must report an offsetting amount of taxable income. For example, in the example earlier where the investor is allocated $19.80 in book depreciation in a year, but there is only $15 in total tax depreciation, he would be able to claim a tax loss of $19.80 under the remedial method. The developer would have to report income equal to the gap of $19.80 minus $15 = $4.80.

Use of the remedial method has the effect of requiring the developer to pay taxes on any appreciation in the project when the tax equity funds over the same period the project is depreciated.

Pre-Tax Return

The model should also calculate the pre-tax return for the investor. Most investors require a pre-tax return of at least 2%. This means that the cash and production tax credits the investor is projected to receive, when discounted at 2%, must equal or exceed the amount of his investment. Investors want at least this level of return to ensure that they are not viewed as having invested solely for tax benefits. The IRS confirmed in guidelines in October 2007 that production tax credits can be treated as equivalent to cash. They are a substitute for higher electricity prices.

Most equity investors appear also to treat the investment tax credit in solar deals as a cash equivalent for purposes of the pre-tax return test. The IRS has not taken a position yet.

Solar Issues

In solar projects, the parties are entitled to an investment tax credit in place of the production tax credits that are claimed in wind, geothermal and biomass projects. The investment credit is claimed in year one when the project is placed in service. It is 30% for projects placed in service by December 2008. It drops to 10% after 2008. Congress is expected to extend it at a 30% level, but may not get around to doing so until 2009.

The credit must be shared by partners in the same ratio they share in income in the year the project is placed in service. However, because solar deals generate losses for at least four years due to depreciation allowances, it is important to hold the 99-1 sharing ratio used in the first year in place for at least a year after the deal starts generating income, lest the IRS argue that the 99-1 ratio for sharing income was illusory.

Investment credits vest over five years at the rate of 20% a year. If the solar project is sold or the investor disposes of his interest in the partnership during the first five years, then any investment credit he was allocated will be recaptured to the extent it has not yet vested. A reduction by more than a third in a partner's sharing ratio for income will also lead to recapture of any unvested investment credits.

A partnership must reduce its basis in any solar project by half the investment credit on the project. For example, if a project cost $100 and it qualifies for a $30 solar credit, then only $85 can be recovered through depreciation. The depreciable basis is reduced by $15, or half the solar credit. The partners must also reduce their outside bases and capital accounts by the same $15. They do so in the ratio they are allocated the tax credit. If the tax credit is later partly recaptured, then the basis adjustment is commensurately reversed. ◎

Toll Road Outlook

Chadbourne hosts a meeting each year at its offices in New York with P3Americas to discuss the outlook for privatized road projects in the United States. The meeting this year was in March. The following is a transcript of the discussion. The panelists are Michael Kulper, senior vice president of Transurban North America, Victor Sultao, executive manager for the United States and Canada for BRISA, Bob Dewing, a managing director of Citigroup, Fernando Ferreyra, with the transportation and social infrastructure team at Babcock & Brown, Alec Montgomery, managing director and head of infrastructure for Royal Bank of Scotland, and Tim Vincent, a managing director with Goldman Sachs. Steve Howard from Lehman Brothers and Steve Greenwald from Credit Suisse participated in the discussion from the audience. The moderator is Doug Fried with Chadbourne in New York.

MR. FRIED: Before we launch into the discussion, let me mention some of the things that have recently been happening in our industry.

SH-130 segments 5 and 6 in Texas just closed.

Both the Capital Beltway HOT lanes in Virginia with Transurban and Fluor and the Northwest Parkway in Colorado with Brisa, CCR and RBS closed in 2007.

In Florida, the Miami Tunnel project is moving forward with Babcock and Bouygues, as is the I-595 and the Jacksonville Outer Beltway bid process.

In Virginia, a request for qualifications for the Midtown Tunnel is expected to be released early this year.

In New Jersey, it currently looks like public-private partnerships for existing toll road assets will not go forward, but Governor Corzine is talking about increasing tolls by 50% every four years from 2010 to 2022.

In Pennsylvania, the state is talking about privatizing the Pennsylvania Turnpike.

Other public-private partnership activity is occurring outside of the toll road area, including the potential privatization of Chicago's Midway Airport and the privatization of parking meters and garages in Chicago.

All of this has been occurring against the backdrop of a very troubled economy, and that's where I would like to start today. As part of that, there are well publicized problems with the monoline insurers who have used their high credit ratings to guarantee repayment of debt. The monolines are being downgraded. Alec Montgomery, how much of an impact will the downgrades have on the public-private partnership, or PPP, market?

Monolines

MR. MONTGOMERY: The monolines have done some interesting deals in the public-private partnership sector. Their participation helped people address a lot of the long-term debt capacity issues associated with these deals. But probably the greater impact of the monoline crisis is the effect it will have on the overall financial markets.

We saw monolines in a handful of deals in North America. While those deals were very competitively structured in terms of the type of financing, at the end of the day, they were probably investment grade-type deals that could attract capital from other sources. The biggest challenge I see with the monolines falling away from this sector is how you put these long-term deals into the bond market. Because, to date, the only way we have seen bank debt get refinanced in the bond market on toll roads is with a monoline wrap. It is a challenge that we have to continue to work on.

MR. FRIED: Victor Saltao, when you were involved in closing the Northwest Parkway, how did the monoline problems affect the closing and your decision making?

MR. SALTAO: They caused a delay of several weeks. We expected to close the transaction between August and September, but that proved impossible. Losing the price protection of the monolines was tremendously challenging for our company. We ended up borrowing from banks without a monoline wrap.

MR. FRIED: Bob Dewing, what impact will there be on future deals if monoline wraps are not available? How will the structures change?

MR. DEWING: The issue that monolines dealt with very neatly is that they took the term risk, but they didn't take the principal risk. The principal risk was deemed to be investment grade. But the monolines took the term risk and the refinancing risk. That loss in the market will make it much more difficult for toll roads and equivalent infrastructure projects to get refinanced. We are going to have to go back to the old days, where we had a series of bonds with various maturities. Highway 407, which predated all of this in Canada, was financed purely on a series of 7-, 8-, 10- and 12-year bonds. This ensured that you only had a certain number of maturities each year, and you had a waterfall of locked up cash to be able to deal with that. I don't think this is a business that the monolines will be in for some time. They have their own capital issues, and the monolines will / continued page 28

Only a handful of US toll road projects are expected to get done in 2008.

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probably spend time going back to their old municipal business. We will have to design new structures, with sponsors taking some of the refinancing risk.

MR. FERREYRA: I think the challenge, going forward, will be the lack of monoline appetite vis-à-vis the political landscape. One of the things we're seeing very clearly is it is much easier politically, in any state, to go after greenfield projects, or new construction, as opposed to brownfield projects, or privatizations of existing highways. Greenfields are exactly the kind of deals that the monolines, even before the meltdown, were shying away from. The monolines were not particularly fond of these kinds of deals before the crisis, and now it's going to be even tougher than before.

MR. HOWARD (from the audience): I would like to make one comment related to monolines. It is correct that risk has been repriced in the U.S. capital markets, big time, but the markets are open and functioning, including with the monolines. We expect transactions will get done this year without getting into a debate about whether they are publicly delivered or privately delivered. We expect transactions will get done, big transactions, with letters of credit as well as with monolines. In fact, over the last couple of weeks, major deals have been priced and underwritten by Lehman and some of our competitors. In one case, on a major project in Texas, the deal was many times oversubscribed, including with MBIA, and insured as part of the credit package. Then yesterday, there was a private activity bond, tax-exempt deal, underwritten by Lehman with MBIA. Risk has been repriced, but the markets are open. We will see things settle down over the next couple of months.

The downgrades of monoline insurance companies are making it hard to finance projects in the bond market.

Collapsing Dollar

MR. FRIED: Let's turn to some other sources of turmoil. The US dollar is continuing to lose value against European currencies. Victor Saltao, how will a devalued dollar affect foreign investment in the US toll road sector?

MR. SALTAO: In my company, these infrastructure deals are looked at with a very long-term perspective. The fundamentals of the economy are key elements for the investment. However, while the exchange rate will be one of those elements, given our long-term perspective, we do not rely on current currency performance. We hedge this risk — not only the risk to our equity, but also to our debt. We are very comfortable managing currency risk.

MR. FRIED: Is the devaluation of the dollar giving an advantage to non-US companies? Are they looking at this and saying, "Let's grab ourselves a bargain"? Michael Kulper?

MR. KULPER: I think this is a politically expedient discussion in some respects. What I mean is, the emotional argument put forward is that the dollar has been devalued and foreigners are going to come in and pick up our assets, our essential infrastructure, for pennies on the dollar.

The fact is that just as the equity investment in a foreign currency gets cheaper, the cash flows that come back over the life of that investment have also been devalued. So if you look more closely at it, there's a symmetric relationship between those two things. We've never really faced a capital constraint in terms of whether something was worth 1x or 2x or 3x in a local currency. So, I think that's fairly irrelevant. The issue is not the devaluation of the dollar, but the volatility in the currency markets, much like the debt and equity markets. Most responsible investors in this space hedge and are looking to protect against in volatility. High volatility results in more costs. So if anything, I think the volatility of the marketplace is unhelpful.

MR. FRIED: Fernando Ferreyra, does the analysis change if we are talking about new construction as opposed to pure privatization?

MR. FERREYRA: It depends on a couple of variables. The first one is, what kind of investor are you dealing with? If you are looking at a strictly financial player, looking at a privatization, brownfield player who is hoping to flip that asset around in a year, maybe the person wants to take advantage of a short-term situation like that. I agree with Victor Sultao about the very long-term nature of these assets. Hopefully, investors who are willing to keep the assets on their books will get the returns over a long period of time.

The other point is closer to Michael Kulper's rationale to avoid the equity being in one currency, and the cash flows being in another. We just closed our US infrastructure fund, receiving the money in dollars. It is much easier if the equity is in the same currency as the cash flow.

Slowing Economy

MR. FRIED: Will a slowing US economy bring reduced tax revenues? Even in the past five years, when the economy was robust, states had problems meeting their transportation budgets. Will a slowing of the economy cause more states to privatize assets or enter into public-private partnerships for new construction? Tim Vincent?

MR. VINCENT: There is a lot of concern about the potential recession and the effect it will have on the economy. Whether it will be a mild recession or a severe recession is hard to say. The recession alone won't create deficits, but consider that municipalities are already facing one of the worst municipal bond markets they have ever experienced, so their borrowing costs are increasing for capital projects. Many states have budget deficits on top of that. This suggests the door is open to having conversations with state officials that, perhaps, we were not that fruitful when we had them a year ago. That said, even a concessionaire, who is looking to raise capital to support a PPP transaction, faces higher costs. It is important to manage expectations with municipalities.

MR. FRIED: Where will the money come from for needed public infrastructure projects? It needs to come from somewhere. Michael Kulper, will the effect of a slowing US economy be different for new construction as opposed to pure privatizations?

MR. KULPER: Even when times were good and tax revenues were flowing in, there was never enough money for new construction. So in a sense, the recession is kind of irrelevant. The realities are that public sector funding for infrastructure has systematically declined in real terms over the last 30 years. The gas tax, in real terms, is about a third of what it used to be. Vehicle miles traveled continue to grow at up to 3% a year. Lane miles are not keeping pace with this growth. The interstate highway system is 50 years old, and the design life of most structural elements is 50 years. We have tens of thousands of bridges in this country that are structurally deficient or functionally obsolete. As the money trickles down from the federal level, to the states and to the localities where projects must be done, there is never a critical mass of money available to do projects.

The issue of a slowing economy also presents problems for private sector funding of new construction, due to the fact that revenues for these projects in the near-term will not be as high as they once would have been in a projected sense, because traffic and revenue are correlated with GDP.

Another issue is that in the environment created by a slowing economy, risk assets -— be they debt or equity —- are repricing. So capital is more expensive, whether it is municipal or private. For new construction projects, the issue has always been, are they feasible, and in this environment, it is tougher to get the numbers to work.

MR. SALTAO: I think we should focus on the fact that the problems are still there. The congestion remains, as does the existing deficit in capacity to maintain existing facilities. The problems are there, but the needs are also there. The economy is slowing, everyone has to make better calculations, better estimations, about everything. But we should not make excuses. We should move forward because in five years, 10 years, the problems will have gotten worse. We should focus on the solutions, on how efficient the private sector can be in delivering infrastructure. How innovative it can be, how creative it can be and how it delivers value.

Federal Role

MR. FRIED: Michael Kulper, is the federal government doing enough?

MR. KULPER: The federal dynamics around this industry are quite interesting. You have reauthorization, which is coming next year. You have the debate at the Congressional committee level about how significant a role the private sector should play versus having federal oversight and control. My view is that the funding of infrastructure isn't given the priority at the federal level that / continued page 30

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it should be given. There has been systemic underinvestment in this industry. The funding mechanism for this industry is effectively broken. There is a reliance on the gas tax, yet politically, no one can increase the rate. So politically, there seems to be almost no alternative other than turning to private solutions.

It is troubling that there continues to be significant debate about that basic fact. The more difficulties there are in the political arena and the lack of clarity and direction to solve the problem, the longer it will take to start to roll out solutions.

As an initial step, we need to get clear policy mandates. Hopefully, after the 2008 elections, there will be a certain degree of clarity brought about through reauthorization, which will happen sometime between 2009 and 2011, depending on whether the bill comes in on time or two years later, as it did last time. This will bring about a clarity of framework. Then you have the issue of how much regulation there is in terms of what the private sector can and can't do. Hopefully the balance is struck at a level where there is clear public interest protection and oversight, and definite rules are established. Once this occurs, then the private sector will be able to do what it can to solve problems, which is to be creative and innovate and bring funding solutions to solve very real needs.

Municipal Debt

MR. GREENWALD (from audience): Can someone tell me why, when you're looking at a massive toll road where, by far and away, the largest component of its costs over time is capital, a municipal bond issued by the Jersey Turnpike Authority or the Pennsylvania Turnpike Authority isn't always going to be a cheaper solution for the US citizen than the higher cost of capital that commercial banks and private investors are going to require?

MR. VINCENT: That's the ultimate question. Why would you ever even pursue this? The problem is, it can't always be about cost of capital. If you are just going to zero in on cost of capital, then it will always be difficult to answer that question. It is also about risk transfer. Risk transfer is a very important component to all these transactions.

Texas has a moratorium on new toll roads. Until the politics settle, developers may be reluctant to commit large dollars to bid on projects in the state.

MR. GREENWALD: The way I see it, what Governor Corzine is talking about in New Jersey is basically, keep it in the hands of the state, issue municipal bonds, and do the same kind of financing that you guys would do, but do it on a tax-exempt basis.

MR. MONTGOMERY: Steve, tax-exempt financing is just a mechanism to give a federal subsidy to a project. The government can do that by giving a grant, or by allowing a state to use tax-exempt financing.

MR. GREENWALD: But as a citizen of New Jersey —- I'm not a citizen of New Jersey, but if I were a taxpayer in New Jersey — isn't it a better solution for me to have the government issue tax-exempt bonds that are going to transfer the risk to the bondholders, just as the risk is transferred in Indiana to the banks? In that situation, you have the risk transfer. The state keeps the asset. It is not selling it to guys who might require a 12 or 15% rate of return for the equity. I understand the argument that you guys operate it more efficiently. I don't fully understand or appreciate how much that really means. Maybe it means a lot more than I'm aware of. But I do know that the overriding cost associated with toll roads is still the cost of capital. So help me understand why a revenue bond that transfers risk to those bondholders isn't a better solution to the citizens of a particular state.

MR. KULPER: Let me jump in here. I think there is a better argument here, which is, tax-exempt debt is available to PPPs.

The cost of debt capital doesn't have to be any different in a public model than in a private model, particularly for new construction projects. I think you are taking a very narrow funding view, whereas you need to look at what a PPP is in a broader sense.

The cost of capital is, obviously, a very important element. For example, in our Capital Beltway project, our funding mechanism is tax-exempt senior debt. You can't ignore the efficiency arguments and the innovation arguments. When discussing the provision of transportation services, you need to take into account what the private sector can deliver in a PPP model where there are risk transfer and incentives to operate efficiently and provide better service, versus a typical municipal structure where, to be honest, you create public funding corporations where it is all about perpetuation of a set of political dynamics, not necessarily the best service or economic outcome.

MR. GREENWALD: So why not have the state outsource it to you guys?

MR. KULPER: Because if you sign people up on contracts or subcontracts, what you find is that people execute in accordance with the letter of those contracts, and soon they are looking for change orders or they are doing the minimum necessary, as opposed to actually optimizing the service and the value of the asset.

MR. MONTGOMERY: I would also throw in that you don't pay that 12 to 15% return to the private capital for nothing. There is a value proposition there. When tax-exempt bonds are used, the federal government provides a subsidy. It is there, and people are going to take advantage of it as they did in Capital Beltway.

MR. GREENWALD: If you could do it all the time the way you did Capital Beltway, maybe that's a solution.

MR. SALTAO: When we are talking about risk transfer, the US does not have the maturity of the European markets, where these issues have existed for 30 or 40 years. For example, traffic risk is a dramatic risk. There is a premium for that risk, and when the economy slows, as Tim Vincent just mentioned, everything slows. The traffic decreases, and you cannot raise the tolls as expected. These are deficiencies that you have to work on and are costs to be accounted for in your business model.

Depth of Financial Market

MR. FRIED: Let's turn to another subject. How much depth do you see currently in the financial markets for financing PPPs? If the lenders are pulling back, will it be harder to finance these projects? Bob Dewing?

MR. DEWING: It is a calamitous market right now for all types of debt. However, I think PPP debt, as with the best projects, still is being received favorably by the market. Many projects in Europe have been financed in the last six months. Even in the US, I think the sponsors will still find many financiers keen to participate in PPP projects. What is completely missing right now is the bond market as a take-out. The banks are going to have to take that risk for an interim period of time. There is no retail market or secondary syndication market for PPP-type assets. There are just no long-term holders coming on the secondary level. The senior lenders who are in the market all the time are still willing to participate, but they are finding that they are having to hold bigger pieces for longer than they would have liked in the past. That is less than appetizing for institutions with capital constraints. The better projects will still get the capital. The marginal projects, I'm afraid, are going to struggle.

MR. FRIED: if lenders are providing mini-perm loans, will there be refinancing or restructuring at the end of those mini-perms?

MR. DEWING: The mini-perms now are five to seven years. I don't think anybody anticipates this to be a five- to seven-year problem.

MR. FRIED: Let's hope not. Michael Kulper, how much of an impact did this have on the Capital Beltway closing in December?

MR. KULPER: It created execution issues. I think the point has been made correctly that good projects with good sponsors are getting done. It is as much an issue around execution, that is, how you do your execution and what the execution costs will be, but fundamentally good projects done by credible sponsors will get done in this market. I think the difference is that a year ago, the quality control probably was not as rigorous as it is today. It was relatively easy to go into the market and get both debt and equity capital. There was not as much of a focus on the underlying project or the underlying business model or the underlying sponsors.

There will be a flight to quality in this environment, and I think that will result in the cleaning out of some marginal players on the debt side and on the equity side. But those sponsors who have a good track record and are established will benefit from an environment where / *continued page 32*

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the risk-reward equation has shifted towards getting better returns for capital.

MR. FRIED: Alec Montgomery, do the problems in the financial market have a different impact on the bank market than on the bond market?

MR. MONTGOMERY: Initially, most of the focus has been on the bank market. That is where all the headline losses have been taken. But at the end of the day, it is a question of liquidity and de-leveraging. We started to see it rip through all different pockets of liquidity. If you step back, it's really a question of the difference between high-grade credits and non-investment-grade or lower rated non-investment-grade credits where the impact is probably equal both across the bank and bond markets. The single B market is pretty well shut. The higher-quality projects, certainly, and the higher-quality credits and sponsors in the market, who have strong relationships with financial institutions, are not going to suffer like the rest of the market.

MR. FRIED: So it is back to basics. A strong project with strong sponsors should succeed.

MR. MONTGOMERY: It is going back not only to risk and return, but also longer-term perspectives on relationships and where investors want to drive the business.

MR. FERREYRA: I have some comments that tie in with the questions that Steve Greenwald asked earlier. I think that the types of assets, toll roads in this case, that may prove more resilient are the ones that have greater profits. These are projects where traffic risk is kept on the public side. This is one of the reasons that such projects are put to the private sector, of course. These are deals where, essentially, you are still likely to see substantial appetites. In Florida, for example, we are working on the Miami Port Tunnel and, hopefully, I-595. Those are projects where you will see, probably, more appetite and higher quality kinds of structures. Hopefully there are going to be more states that use the successful formula that Florida has been using for the last year and a half.

Public Perception

MR. FRIED: I want to talk about public perception for a moment. Michael Kulper, America Moving Forward is a coalition that has been formed recently by some members of our panel. What does this coalition plan to do to convince the public of the value of public-private partnerships?

The Capital Beltway is a good model. Drivers can choose to pay tolls to use new lanes.

MR. KULPER: The coalition is primarily about education. There are many misconceptions: such as that the public sector always owns the assets and the assets aren't foreign owned. The public sector is always in control of the project because it gets to set the rules of engagement. It writes the concession agreements. It specifies contract terms that ensure that the asset is operated in the public's interest. Performance standards are often well in excess of standards for public-run assets. You actually end up with a premium facility. There are always consequences for failing to live up to those standards.

Then there are the issues related to risk transfer. There is real value, for example, in doing turnkey contracts where price and schedule are agreed and there are real financial consequences for failure to deliver. We only have to look at the debacle that was the Big Dig to see what happens when the public sector doesn't shift risk to the private sector: you get schedule delays, and you get cost overruns.

Every PPP is different. What the public sector should be doing is making sure that the deals are structured so that the public interest is protected. In most cases, that is successfully achieved and real value is created out of these processes. This coalition is aimed at educating politicians and the communities at large about the value that PPPs can bring.

MR. VINCENT: The coalition exists to address some of Steve Greenwald's questions. Steve should log on to the website, and he can read all about the value of PPPs. It is truly a communications effort. It has a lot to do with the message itself. What are you asking the public to accept? By doing this potential structure, it frees up so much more capital for hospitals and education.

MR. DEWING: It is also a movement from the public sector providing a service to the user paying for the service.

MR. FRIED: Bob Dewing, has the public perception gotten worse, better or stayed the same since a year ago?

MR. DEWING: It has gotten worse. PPPs are being dragged through the mire by the press. There is some time to go before there are enough successfully operated projects for people to see that there is, truly, a better service with the private sector. You can look at Corzine's proposal, which was well thought out and put together, and was virtually dead on arrival in the press. Before he got to present his case in the public meetings, the press and the public had already decided.

MR. FRIED: Governor Corzine has proposed raising tolls by 50% in 4-year increments, in a non-PPP environment with a public benefit corporation. Does that actually help the PPP cause?

MR. KULPER: Toll-rate setting is entirely a public sector decision. It has no bearing on whether to use a public benefit corporation or a concessionaire for a road project. I think that our industry has suffered somewhat from the fact that there were clear public policy decisions around toll-rate setting for some of the earlier PPPs, and I'm referring specifically to Chicago and Indiana, where they built in these 75- and 99-year deals, and they allowed tolls to increase per schedule, which they set to increase in real terms substantially over time. That was for the explicit purpose of maximizing the value of the asset. That was a decision that was in the public sector's control. This isn't a private decision, it's a public decision.

MR. FERREYRA: Just thinking about public perception after the bridge collapse in Minnesota last year, I think that was like Andy Warhol's comment: suddenly we got our 15 minutes of fame and the public's attention. I think that it increased public awareness to a small extent, but the public has a short attention span. Nowadays people are talking about elections, and public infrastructure is way down the waterfall.

MR. FRIED: Talking about public perception, in an interview with P3Americas, former Representative Dick Gephardt suggested that the use of limited toll lanes on non-toll highways could be used to gain wider acceptance of PPPs in the United States. Alec Montgomery, what are your thoughts about the proposal?

MR. MONTGOMERY: Absolutely. It's clear that most of the new road capacity is on existing, very congested roads. The idea of providing that new capacity as an option to the user to pay the tolls for the faster-moving lanes, as opposed to using the existing capacity and choosing to be in traffic, is hard to disagree with. From a public perception perspective, it's a win-win. Anyone who doesn't like the idea of building that new lane can simply go into the existing lanes and suffer the consequences. We are going to see those types of projects increasingly, in fact. An example is the Capital Beltway.

MR. KULPER: That's exactly what Capital Beltway is. The fact of the matter is that the last expansion of the Capital Beltway was in 1977. Traffic had more than doubled since then. The public sector had been trying to figure out how to fund an expansion of the Capital Beltway for more than a decade. It could never figure out how to do it, and absent a PPP, that expansion in capacity never would have occurred.

It's not just about capacity, or even / continued page 34

Since the cost of capital is the largest single cost in highway projects, why isn't the state better off financing in the tax-exempt bond market and retaining ownership?

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primarily about capacity. It is a recognition that one of the pressing problems we have in transportation today is that you have these big cities, highly urbanized areas, where a disproportionate amount of the economic growth is occurring. That causes congestion, which is a significant impediment to the ongoing health of the economy. What delivering new capacity, at a price, does is ration that capacity and helps to manage congestion, using price as a lever to do that. It really is a win-win, because people can pay for an enhanced service. But even those people who choose not to pay for that service get other benefits. Typically, these are often HOV lanes, so people get to use them for free if they're prepared to carpool. The lanes often allow mass transit to go for free and, thus, encourage mass transit use of these corridors. Even if people choose to sit in their cars, as a single-occupant vehicle in the existing general lanes, the fact is, these HOV lanes are going to take traffic off of the existing general lanes and reduce the congestion of those lanes. Literally every user-group wins.

To jump around a bit and address the issue around criticism of our industry, the Capital Beltway HOT lanes project is in the nation's capital. It is driven by all of the public policy-makers on the Hill. The project has been incredibly well received; there hasn't been any major criticism of it. There has been some criticism. Projects where you can demonstrate a clear public policy benefit as far as capacity, levels of service and that produce a win-win for all user elements are projects that are going to do well.

MR. FRIED: Did you face foreign ownership issues?

MR. KULPER: No.

MR. SALTAO: People need to understand the value of using new capacity —- more safety, faster traffic, less time traveling, innovative services, better asphalt quality, whatever. People need to see that value; otherwise, you are just shifting the perception of toll increases to the private sector, which, as Michael Kulper correctly pointed out, is not decided by the private sector. Toll increases should be determined by the public sector—the policy-makers should do that.

Risk Allocation

MR. FRIED: That's a good segue into our next topic. As more deals have hit the market over the last year or so, people involved in this industry are getting a better sense of how risks are being allocated. The question is, do you think the states are attempting to allocate too much risk to the private sector?

MR. FERREYRA: I call this the modern law dichotomy. Sometimes the private sector gets transferred risk that it can't manage. This is something that is getting a bit closer these days, for a couple of reasons.

We saw it in Texas in a couple of contracts. We saw, for instance, pre-existing conditions, taxes, hazardous materials, and other risks where, of course, if you are sitting on the public sector side, it is better to become the new champion and throw that, if you can, to the private sector. Maybe a year, a year-and-a-half ago, some developers were willing to take that risk; just close their eyes, jump, claim that they got it done. I would say that these days, banks, and also equity, are going to be extremely careful in what they take because they may not be able to transfer the risk.

Transferring risk to parties who cannot manage the risk can only result in a very inefficient pricing of the risk. One case is pre-existing conditions. The moment you, as the developer, try to pass that along to your construction partner, you start hearing a lot of noise, to say the least. We are fine managing and accepting those risks that are under our

The cheap dollar will not necessarily bring in more foreign investment. The returns earned by investors are also in dollars.

control. But other risks that are way beyond what the concessionaire can control should not be transferred or, back to Steve Greenwald's point, the taxpayer will end up paying more than he would otherwise.

Pennsylvania

MR. FRIED: We can't leave this roundtable without mentioning Pennsylvania. Given the options, it seems that the possible and maybe probable outcome is that the Pennsylvania Turnpike will be privatized. One suggested way of doing so would be to break up the Pennsylvania Turnpike into three segments. Do you think that the state could raise more money with such a structure? Does such a structure make sense?

MR. SALTAO: Having one contract with 600 miles is not an issue. BRISA has a contract for 1,000 kilometers; in terms of operation, that is not an issue for a concessionaire. On the other hand, we see many recent transactions involving small segments, between 10 and 20 miles, but we don't see many larger transactions. The public needs to evaluate how private sector involvement brings value to the table. Smaller transactions make this easier. Also, as the public sector gets more experience with these smaller transactions, and learns how to be more efficient, it may move towards larger transactions. However, the procurement processes take too long and are too expensive, and given the decreased feasibility of moving transactions through the market in the coming months, breaking the Pennsylvania deal into segments makes sense. There is a big question mark over whether the market can handle such a huge transaction.

MR. FRIED: Alec Montgomery, thinking about it in terms of financing, would breaking it up into three pieces make financing this kind of project easier?

MR. MONTGOMERY: Clearly, very big deals are having more difficulty because of the liquidity issues in the market. In terms of delivering firm underwritings from the bank market, smaller deals are probably easier to get done than one big Pennsylvania deal.

I can certainly see the logic in saying that breaking it up into three smaller deals will achieve more efficient financing in each one. I'm not sure, at a sponsorship level, or from an equity level, that to break up the Pennsylvania Turnpike is, necessarily, the best outcome. I also question whether that type of proposal was made at this late stage of the process to achieve a better outcome for the state, or to depart from the process that the state has been undertaking for the last six to 12 months.

MR. FRIED: The real question I want to ask the panel is do you think Pennsylvania is going to happen?

MR. DEWING: Why don't we take a vote?

MR. FRIED: Let's take a vote by a show of hands. Do people think Pennsylvania is going to happen this year? No one? Most people are pessimistic.

Texas

MR. FRIED: Let's shift from Pennsylvania to Texas. All we kept hearing for a couple of years was, "Texas is open for business." We all know what happened with the moratorium on the eve of our panel last year. Tim Vincent, you are involved in Texas. Will Texas reopen for business?

MR. VINCENT: I think Texas is open for business. It's fair to say, as you mentioned in your opening comments, that we just had financial close on an important transaction. That said, I think the pain is still there. SH-121 — which is what you were talking about at this time last year -— got done, but not without some pain. The deal was downgraded, which limits the financial flexibility going forward. Texas has a moratorium on new deals, but there are projects that are not included in the moratorium. Those are important projects to pursue. Our belief is, for the correct PPP structure that appeals to the right public policy, the market is open. Texas is a big state.

MR. FRIED: With huge needs.

MR. VINCENT: Huge needs. The needs have not changed. The question is establishing the right model for the project. The question to be asked is, Cintra closed on a very important transaction 12 months after the moratorium without any real negative feedback. How did that happen?

MR. KULPER: I think the interesting question will be, as projects come up in Texas, will sponsors show up? Not so much will sponsors show up in the sense of putting their qualifications in, because that's essentially a marketing exercise that results in expenditure of limited resources, but as you run a bid process and you ask people to spend $10 to $20 million, and finance projects costing $1 to $2 billion, are sponsors going to have enough confidence in the integrity of the procurement process and the ability of the public sector to get the project to close? As we sit here in a more difficult environment today versus a year ago, we are a bit more selective about where we / continued page 36

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spend our finite resources. I think that's the calculus for sponsors. The fact that Cintra closed a project last Friday is fantastic for the market. I think the market will watch L.B.J. very closely, which is a process that's underway right now with bids due very soon. We will be looking for evidence that projects are moving forward in Texas before we jump in with both feet again.

Final Thoughts

MR. FRIED: We are almost out of time. Let me ask each of the panelists for a final comment about the future. Bob Dewing?

MR. DEWING: I believe PPP is the solution for the future, because taxes aren't going up and the legislators aren't going to raise the fees for the public sector delivery of services. Even though we only see two or three transactions a year, this is something we will continue to see. Use of the PPP model will continue to grow over time, as it is the only solution.

MR. KULPER: I think the fundamental problems of congestion, deteriorating infrastructure and lack of funding are systemic issues. They've been issues in this country for 20 years. The debate is about how fast PPP as a partial solution will come, and I emphasize it is really only a partial solution for some of these issues.

I have been doing this panel for three years, and I have always been on the bad side of it, in terms of saying it is going to come more slowly than people think. I think I have been proven consistently right about that. It is pleasing to see transactions have closed, but it is a case of continued evolution; there is no revolution.

I think a handful of transactions will get done this year, but only a handful. The longer-term trend is clear; this market will continue to grow. At present, it's all doom and gloom about where the financial markets have gone, but I actually think the market is healthy. I think there was an element of almost irrational exuberance around our industry over the last couple of years. There were many more people interested in playing in this space than there were transactions to do. I think that our industry, on both the debt and the equity sides, on a global basis, not just a US basis, has not looked closely enough at the underlying transactions as opposed to the risk. There have been, and will continue to be, difficulties around some of the transactions that have been structured over the last three to four years. I think the focus in the current environment on correctly pricing risk and allocating risk is one that is going to be to the good of the long-term health of our industry. As I've said before, correctly structured transactions with credible sponsors will continue to get done. They are good for our industry.

Potential volatility in exchange rates is a bigger issue for foreign investors.

MR. SALTAO: I would stress two points. One is that PPPs are a new concept and everyone is learning: states, local transportation authorities, municipalities. The better advised they are, the more clear the procurement processes are, the faster they can be, and as a result, the less expensive PPPs will be for the sponsors and the market. No one wants to spend millions on transactions that go nowhere. So, efficiency is a key element for PPP programs. And once again, execution. Execution means every state, or the major states that have programs, should execute, because the need remains and must be fulfilled. As everyone knows, it's not about a lack of equity, and even with the current debt market problems, we have the capital; so let's do it.

MR. VINCENT: I wasn't on the panel last year, so I had the benefit of reviewing some of the quotes from last year. A colleague of mine, Greg Carey, had some pretty colorful quotes. I took notes. As I read it, a year ago, the issues that they were facing, at least, the ones that were described by the panel, were a lack of transactions, we had a public perception issue, we were describing what was, in my colleague's words, "a train wreck in Texas," and there was, clearly, a lack of courage to get transactions done. The only optimistic tone that came out last year was there appeared to be an unlimited source of equity. I wonder where we are today?

Things have changed. There is no longer an unlimited source of equity. Actually, I think a lot of the time we all focus on the major deals. We spend so much time focusing on them, we see their pitfalls and the difficulty in getting approvals at the legislative level. But there's this undercurrent of momentum when you look at Capital Beltway. That is a transaction that should be replicated. We see what happened in Texas. Cintra has quietly done a deal that has been very rewarding for it amid the whole outcry about what is going on in Texas. I agree the market is healthy. I think the debt market is going to be right-sized. I think attention to credit and pricing has come back, which is important. I, too, am optimistic, especially when you look back and see the way things were.

MR. FERREYRA: The private sector will remain able to deliver much needed infrastructure efficiently. Public deficits will remain in this country, both at the federal and state levels. Therefore, regardless of the political discussion, which is very strong right now given the election, PPPs, P3s, public-private concessions -— whatever we want to call them — will remain a feature.

MR. MONTGOMERY: When I reflect back on 2007, for our business at RBS, which is an infrastructure-focused business, including PPPs and toll roads, there was a significant inflection point as far as deals that came to market and actually got done. The general trend is positive. When you look at the year, it was primarily the port sector, it was primarily the acquisition of existing assets with just a handful of true PPPs and toll road transactions. Northwest Parkway closing, Capital Beltway closing and another road in Quebec, A-25, all of them getting squeezed in at the very tail-end of the year.

When we look at 2008, I think we will continue to struggle with some new challenges on the financing side, with financing capacity and appetite this year, but, I think, we are gaining momentum. We, as an industry, haven't had a great track record with getting these deals done in an efficient and timely manner. But as each state goes through its processes, it learns. Everyone is optimistic about Texas learning from the past, about Florida learning from its experience, and about Virginia, the state with the greatest experience, being able to deliver these types of projects in a much more efficient manner. ◎

Ten Legal Traps for Investors in India

by Anand S. Dayal, in New Delhi

Ten legal requirements are traps for the unwary for foreigners investing in India. Each is relatively uncomplicated but often holds up and frustrates investors. Knowing what they are and taking them into account at inception will reduce transaction costs and reduce the likelihood of false starts.

Fair Value

The first is share price restrictions. The Reserve Bank of India has rules for how much may be paid or can be charged on exit when foreigners buy shares in Indian companies.

Nonresident purchasers of shares must pay a price that is not less than the "fair value" of the shares. A nonresident seller can receive no more than the "fair value" unless the sale is to another nonresident, in which case there is no restriction on the share price.

The fair value requirement applies both to existing shares acquired through purchase, as well to fresh or new shares issued by an Indian company.

The "fair value" of the shares must be determined using guidelines prescribed by the Controller of Capital Issues, and it must be certified by a chartered accountant in India. If the transaction involves a security listed on a recognized stock exchange in India, then the price must normally be within 5% of the daily average high and low price for the week preceding the transfer. The valuation certificate must be filed with the Reserve Bank of India as part of a regulatory filing that must be made whenever shares in Indian companies are bought or sold.

Public Tender

Transactions entirely outside India may */ continued page 38*

India

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require a public offer in India if the transaction involves an indirect acquisition of more than 15% of a listed Indian company or a change in control of such a company.

A direct or indirect buyer of listed shares must make a public offer if the buyer will end up owning more than 15% of the target should it make the purchase or the purchase will lead to a change in control of the company. The public tender cannot be for less than 20% of the outstanding shares in the target company. The buyer must tender for shares at the price the shares are trading on the stock exchange when the shares are acquired. The obligation to make a public tender applies only to shares in companies that trade on an Indian exchange.

By itself the requirement for a public offer in a domestic transaction is not unusual. What is unusual is such a tender may be required in India for a share purchase that otherwise would take place indirectly and entirely outside India.

In the past, there are several instances where a global acquisition, involving a relatively minor India subsidiary, has triggered the public tender requirement in India, but no public offer was made of shares in the local Indian company due to oversight or incorrect advice. The Securities and Exchange Board of India has required the buyers in such cases to remake the required public tender at the price prevailing at the time of the acquisition and to pay interest and fines. This has spawned substantial litigation, some of which is still ongoing.

Preferred Shares

Preference shares and convertible debentures held by nonresidents are treated as debt in India, unless they are mandatorily convertible into equity. If they end up being treated as debt, then caps will come into play on the use of funds and the distributions that can be made to holders of the shares or debentures.

There are caps on distributions on preferred shares even when the shares are recognized as equity. Preferred shares can receive a maximum dividend of 300 basis points over the prime lending rate of the State Bank of India prevailing on the date that the board of directors of the Indian company approves the issuance of shares.

If treated as debt, preferred shares and convertible debentures must comply with all of the restrictions imposed on external commercial borrowing, including end-use restrictions and all-in-cost ceilings, that are discussed below. They are treated as such borrowing when the shareholder is a nonresident.

Indian companies can borrow abroad, but only to meet foreign currency needs and to pay up to $20 million a year in domestic rupee expenditures.

Companies Act

Compared to modern corporate statutes, the companies law in India is unduly restrictive. Features that are commonplace in other countries, such as the issuance of shares other than for cash, share buybacks, differential shareholder rights as to voting and dividends and "put" or "call" options on listed shares, are difficult to implement in practice.

The Companies Act, 1956 is due for a major overhaul. Until that happens, its somewhat rigid approach to the internal functioning of companies tends to create roadblocks in accommodating the commercial aspects of more complex transactions. The following are some of the most troublesome restrictions in practice.

Shares can only be issued for cash or a cash equivalent except in narrow circumstances. This applies to resident as well as nonresident share purchasers.

Share buybacks are permissible, but only using "surplus" funds that are otherwise available to pay dividends and subject to a limit of 25% of the paid-up capital plus surplus and maintaining a post buyback debt-to-equity ratio of 2:1.

Differential shareholder rights as to voting and dividends are permissible, provided the company has been profitable in the previous three financial years and the shares with differential rights do not exceed 25% of the total issued share capital.

The enforceability of put and call options on listed securities is at present unclear, although such options are common. Options are vulnerable on the grounds that the Securities Contracts (Regulation) Act, 1956 prohibits contracts for the sale or purchase of listed securities (other than spot delivery contracts), except for such contracts that are traded on a stock exchange.

External Commercial Borrowing

Indian companies may engage in external commercial borrowing only for certain permitted end uses. The interest rate and other costs must not exceed an all-in-cost limit that is updated from time to time.

External commercial borrowings are loans taken by an Indian borrower from a nonresident lender, including borrowing from a foreign joint venture partner or investor. At the present time, such borrowings are permitted only to meet the foreign currency requirements of an Indian borrower. However, with prior approval from the Reserve Bank of India, external borrowings of up to US$ 20 million per financial year can be used to meet domestic rupee expenditures. Furthermore, the proceeds of all external borrowings must be disbursed and held outside India. To meet domestic spending in rupees, the borrowed funds can be brought into India only to make actual expenditures. This policy could change.

There are also end-use restrictions on deployment of the borrowed funds. Broadly speaking, external borrowing can only be used to pay the cost of imported capital goods, new industrial projects and for modernization and expansion of existing industrial facilities. It cannot be used for on-lending, investment in capital markets, real estate, working capital, general corporate expenses or repayment of existing rupee loans.

Further, the all-in-cost of an external borrowing is subject to a cap. The all-in-cost is comprised of interest, fees and expenses paid in foreign currency other than any commitment fee. Fees payable in rupees and withholding tax paid in rupees are excluded. For rupee loans, the interest rate must include the swap cost. The all-in-cost ceilings are modified from time to time and vary depending on the average maturity period of the loan.

Cash-Only Purchases

Except in very narrow circumstances, a nonresident buying shares or other securities in an Indian company must pay cash.

The cash-only requirement precludes other forms of consideration, such as a share swap, promissory note or other valuable consideration, including services and intangibles such as technology, know how and trademarks. Furthermore, regulations require that the cash be brought into India through normal banking channels and be received by the Indian company or seller of securities in cash.

Nonresidents buying shares or securities in Indian companies must almost always pay cash. Share swaps and promissory notes are not allowed.

Asset Purchases

In an asset deal involving two Indian companies, the asset purchase price must be routed through the company in India that is buying the assets. Payments made overseas at the holding or parent company level will not be recognized in India.

This has the potential to affect the / continued page 40

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overall structure of some transactions outside India, because of the requirement that actual cash be paid in India as consideration for the asset transfer. Usually in an asset deal, both the seller and the buyer are Indian entities. The local entities — both the buyer and the seller — are often surrogates for the actual party in interest outside India. An example is where a multinational company is buying a group of companies, and the group has an Indian subsidiary. The buyer may want to structure the purchase so that the Indian leg of the transaction is an asset purchase as this may have more favorable tax consequences. (Buyers usually like to have the purchase price reflected in basis in assets so that it can be recovered through depreciation.) Since the assets can only be transferred for cash, it may be necessary for the Indian component of the transaction to be funded separately.

Company Liquidations

The liquidation or winding up of an Indian company is a cumbersome and drawn-out process, even when it is voluntary and the company has no creditors.

It is far easier to register or incorporate a company in India than to wind up a company. India has no modern bankruptcy law, relying instead on general insolvency law. In the case of a company, the Companies Act, 1956 provides for the liquidation of a company and the distribution of its assets to creditors and other claimants. However, even the simplest of cases, a voluntary winding up with no creditors, requires approval from the high court of the state in which the registered office of the company is located.

Tax Withholding

Many payments made in a transaction require that the person making the payment withhold taxes on it. This applies to interest, dividends, rent, royalties, payments to contractors and fees for professional or technical services, among other payments.

The need for an Indian company making the payment to deduct taxes is often overlooked in structuring transactions. As a result, transactions that are often thought of as being economic equivalents — such as an equipment lease versus a financing arrangement, or a price discount versus liquidated damages — could have different withholding tax consequences. The Income Tax Act, 1961 requires the payor to deduct and deposit taxes at specified rates from a broad variety of payments. There are exceptions in favor of tax-exempt entities, such as the International Finance Corporation, but these are not broadly applicable. The withholding rates may be reduced on Indian tax treaties with other countries.

Transfer Pricing

Inter-company transactions between affiliated companies must be at arm's length if one of the entities is located outside India. Significant recordkeeping and filing requirements apply.

All transactions between a nonresident entity and its Indian affiliate that have a bearing on the profits, income, losses or assets of either entity must be at an arm's-length price. The transactions expressly included are the purchase, sale or lease of tangible or intangible property, the provision of services and the lending or borrowing of money. For example, the requirements come into play where a foreign parent makes a loan to its Indian subsidiary.

This could limit the cost savings from outsourcing work to an Indian affiliate, and it creates uncertainty in forecasting the economics of an Indian operation that supplies affiliated entities outside India. ◎

Carbon Reduction Projects in Africa

by Alex Blomfield, in London

Given its obvious need for foreign investment and the fact that, as a continent, Africa is especially at risk from climate change, it may be considered surprising that African countries have been slow to exploit the benefits that the "clean development mechanism" under the Kyoto protocol offers.

This article assesses some of the reasons for this and the continued barriers to CDM investment in Africa.

However, notwithstanding these barriers, there has been a discernible increase of late in CDM activity in Africa and this article also discusses some of the efforts to encourage this trend and highlights some of the advantages for developers in investing in CDM projects in Africa. African involvement in CDM projects not only offers African countries a chance to be a part of the solution to global warming but is also a market that will increasingly demand the attention of project developers, fund managers and other market participants.

Clean Development Mechanism

The Kyoto protocol is an international agreement that was adopted in 1997 linked to an existing United Nations climate change treaty, and has since been ratified by 180 countries, that commits the signatories to take steps to reduce greenhouse gas emissions that contribute to global warming to 5% below 1990 levels by 2012. Efforts are underway to negotiate new targets that will apply past 2012. China and India are both parties, but the protocol does not subject them to emissions limits; the United States signed but failed to ratify the protocol.

The "clean development mechanism" is a tool under the protocol to combat climate change. The CDM allows a country that has committed in the protocol to reduce its greenhouse gas emissions — a so-called "Annex B party" — to satisfy the commitment by undertaking an emission-reduction project in a developing country. Such projects can earn saleable "certified emission reduction credits" for each ton of CO_2 reduced that can be counted toward meeting Kyoto targets. These credits or CERs are generally cheaper for the Annex B party countries than equivalent reductions in their own countries and, at the same time, offer the developing countries in which the projects are situated valuable foreign revenue in support of both sustainable development and climate change mitigation.

According to the CDM website of the "United Nations Framework Convention on Climate Change," Africa is currently home to only 25 out of a total 1,078 registered CDM projects. Of these, almost half (13) are in South Africa — reflecting stronger institutions and a better general investment climate than elsewhere in Africa — four are in Morocco, three in Egypt, two in Tunisia, and there is one in each of Uganda, Nigeria and Tanzania. In contrast, China and India together make up over half of the registered projects (221 and 344 respectively), Brazil has 137, Mexico 105 and even Malaysia has more than Africa with 28.

Africa also contributes only a small share of the total certified emission sales from CDM projects. Of the 139 million tons of CERs that have been issued by the UN since 2005, only around 1.6 million have been to projects in Africa and the vast majority of these have gone to a single industrial gas project in Egypt. According to the World Bank's "State and Trends of the Carbon Market 2008" report, Africa accounted for just 5% of certified emission reduction permit sales last year, with the majority going to China and India and with even Korea and Brazil attracting a greater share of CER sales each than all of Africa.

It is clear that Africa has been bypassed by the world carbon market, a lucrative and ever growing market that was worth $67 billion in 2007.

Carbon emissions reductions are a potentially important source of revenue for projects in Africa.

However, notwithstanding its small share of the CDM market, there are signs that CDM activity in Africa is picking up.

Konrad von Ritter, sector manager for sustainable development at the World Bank Institute, has pointed to real accomplishments in the past year: "There has been a notable increase in capacity development and a growing pipeline of CDM projects, including 14 with already signed emissions reduction purchase agreements with World Bank carbon funds." Last year's 5% share of worldwide CER sales was an increase on 3% in 2006, and Kenya, Uganda and Nigeria all reported sharp increases in transaction volumes. A number of countries in sub-Saharan Africa entered the project pipeline for the first time in 2007 and early 2008, among them Congo-Brazzaville, Mozambique and Senegal. Perhaps most importantly but hardest to / continued page 42

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measure, people are talking more frequently about CDM in Africa with conferences being held on the topic and developers keen to explore the potential of the market.

Barriers

Notwithstanding the buzz around CDM in Africa right now, it is worth noting some of the barriers to CDM investment in Africa.

However, low greenhouse emissions per capita make it harder to achieve meaningful reductions than in developed countries.

It is true of almost any foreign investment that countries that welcome investors, with clear and transparent rules, regulations and policies will have an advantage. This is even more the case for CDM projects, which involve a unique combination of public and private sector cooperation.

CDM in Africa has suffered from lack of supporting institutions and implementing agencies. Until recently there were few capacity-building initiatives to improve this situation, although this is now no longer true. Some African governments still need to be convinced of the development benefits of CDM when faced with capacity constraints and priorities of health and education.

Only 40 of the 55 countries in Africa have ratified the Kyoto protocol, which is a prerequisite for hosting CDM projects or participating in emissions trading under the protocol. Of these, 37 have established the required "designated national authority." It is unclear how many of those African countries have fulfilled the other prerequisites to hosting a CDM project and trading emissions under the protocol, which include having calculated and recorded one's "assigned amount," having in place a national system for inventory, having submitted an annual inventory and having submitted supplementary information on the assigned amount.

There have also been difficulties in identifying eligible projects for CDM in Africa. One of the key reasons for this is difficulty in meeting project applicability criteria. Since Africa's greenhouse gas emissions are low per capita, the potential for emission reductions is more limited.

Finally, much of Africa is very poor and has a shortage of people with the technical and management skills needed to meet CDM standards.

Advantages of Africa

The World Bank's "State and Trends of the Carbon Market 2008" report said that "Countries in Africa . . . emerged in the carbon market and offered buyers an opportunity to diversify their China-overweight portfolios," citing Kenya, Uganda and Nigeria as the main movers in 2007.

Investors have historically pursued so-called "low-hanging fruit," meaning projects that yield the most CERs for the lowest investment. For this reason, larger projects in countries such as China, India and Brazil have predominated over smaller projects in Africa, since the administration costs, often up to $200,000, tend to be unrelated to project size and many have erroneously assumed that African countries' emissions are too low for them to qualify to earn credits for carbon reductions. However, many of the more viable larger projects in the established markets have now been scoped, and in Africa there a number of countries that have hardly been explored for project potential. Opportunities abound in petroleum and gas production and flaring, the electricity sector, mining sector, agro-business and heavy industry, including cement, chemicals, petroleum refining, glass and smelting.

African CERs are usually cheaper than CERs elsewhere. This is partly due to the demand for foreign currency in many African countries.Local currency risk is a key concern for private investors in Africa. Exchange rates are often more unpredictable than those in developed economies, and these fluctuations can have serious negative effects on the rate of return from investments. Carbon credits, on the other hand, are traded internationally and have proven relatively stable since their inception, meaning that returns from CDM projects in developing countries are more secure than other forms of project finance in Africa.

The World Bank promotes the burgeoning carbon trading market as a "tool to help Africa's poor." CERs from Africa offer additional value to project developers and carbon buyers because of their significant contribution to sustainable development – termed by UNDP as the 'development dividend.' Developed country governments and private investors can help Africa meet the "millennium development goals" while simultaneously fulfilling their obligations under the Kyoto protocol.

The proceeds from the sales of carbon credits may only rarely be enough to fund CDM projects in Africa. However, Africa is the beneficiary of strong flows of development aid. There is nothing in the CDM rules that precludes using donor money to support project development, provided that the emissions credits do not go to the donor. The United Kingdom, Japanese and Austrian governments are among those governments that have prioritized CDM projects as a distinct component of their aid programs in Africa. Although much of this assistance is directed toward capacity building, there may be potential in the current climate for Africa to attract donor money for the capital investment required to make projects viable.

The International Finance Corporation and Canadian International Development Agency have identified Africa as an ideal destination for small-scale projects in areas such as off-grid renewable energy, energy efficiency and small afforestation and reforestation. These can be bundled together for simultaneous registration by the CDM executive board.

Encouragement?

In late 2006, a coalition of UN and development agencies, including the UN Environment Program, the UN Development Program, the UN Framework Convention on Climate Change Secretariat, the World Bank and the African Development Bank launched the Nairobi initiative to encourage developing country involvement in the CDM, especially those from sub-Saharan Africa.

In 2007 the United Nations launched an internet-based CDM bazaar (www.cdmbazaar.net) to bring African project developers together with investors, provide a venue for engineers, marketing firms and other service providers, and highlight the opportunities for CDM activities in Africa and other poor developing areas. The agencies participating in the Nairobi initiative are convening an all-Africa carbon forum in Senegal in September 2008 to highlight the potential of Africa for green development investors.

International negotiations on a successor treaty to Kyoto are scheduled to be concluded in Copenhagen in December 2009. In the meantime, efforts are underway to reform the CDM rules, including in ways that would encourage African involvement.

At the December 2007 climate change meeting in Bali, governments agreed to explore ways to expand the CDM into areas that have not been included, such as forest preservation, an area that offers huge potential to sub-Saharan Africa, especially given the continued prevalence and damage to the environment rendered by the high share of wood use in the energy mix of those countries and the vast forests in places such as the Congo basin. Scientists at the Woods Hole Research Center believe a proposal to pay the Democratic Republic of Congo for reducing deforestation could add 15 to 50% to the amount of international aid flowing to that country.

Governments at Bali also agreed to simplify the procedures for applying to the CDM and meeting its requirements. Without compromising environmental integrity, the CDM executive board also needs to reduce the cost of CDM project preparation and registration.

One particular area of recent controversy in CDM rules is the requirement to prove that a CDM project has "additionality," meaning that the project underlying the offset would not have occurred anyway. Recent studies have shown that many CDM projects would have happened anyway and, on that basis, critics conclude most payments for carbon credits do not actually reduce emissions. This criticism goes to the heart of the integrity of the CDM mechanism and is a topic for another day. However, it is relevant to CDM in Africa as a change in the rules on additionality could make it easier to register CDM projects in Africa. This is because many contend that the baseline methodologies currently recognized by the CDM executive board are not suitable for projects in Africa. The CDM executive board has encouraged project participants to demonstrate ways to implement alternative methodologies to show additionality. */ continued page 44*

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The agencies also agreed to launch an adaptation fund, financed in part with money from CDM projects, to support worthwhile green development projects that are not currently eligible under CDM guidelines.

The International Finance Corporation is also doing more to promote CDM projects in developing countries. It is launching a carbon credit guarantee program to reassure investors of the security of African CERs.

The United Nations is considering a new type of bond that would spur investment in clean-energy projects in the developing world, including Africa. The so-called climate bonds would be sold to investors by developing countries in Africa, Asia and Latin America and each security would finance emission reduction projects in those countries. The bonds would be backed by the issuing government, and once they mature, investors would receive carbon credits, tradable securities each guaranteeing a metric ton of carbon dioxide reductions were made. The proposal would simplify the funding of renewable projects in developing countries because each bond would group together multiple clean-energy projects. The advantage of this proposal for Africa is that it would allow African countries to access funding for smaller projects, without potential investors having to research and finance those projects directly as they do now. It is unclear at this stage whether the proposal will be developed as a potential funding source for CDM projects or a separate mechanism.

Overall in 2007, Africa as a continent registered 5.7% GDP growth and a per capita increase of 3.7%. Indications are that growth will only accelerate in 2008 and remain buoyant in 2009. It is clear that African growth is healthy against the background of a faltering global economy, even without involvement in CDM projects.

Notwithstanding this, with the global trade in carbon credits soon expected to top $100 billion annually, there are opportunities to bring Africa, the least developed of the world's continents, more fully into the CDM market. This has enormous potential to encourage investment that would put the continent on a "low carbon development path," encourage the supply of low carbon electricity to its people, reduce greenhouse gas emissions, and help Africa reduce its vulnerability to climate change. Realizing this potential will require not only the dedicated effort of African countries but also increased focus on this market from project developers, carbon fund managers and other market players too. The stakes are high for Africa but success is possible. ◎

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