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Is the US Independent Generator Model Dead?

Independent power companies in the United States are having a hard time persuading utilities to enter into long-term contracts to buy their electricity. Independent power companies generate about 42% of electricity in the United States. Regulated and municipal utilities and electric cooperatives generate the rest. The market share held by independent generators reached a plateau in 2003 two years after Enron went bankrupt. The Public Utility Regulatory Policies Act that required utilities to buy electricity from independent generators was gutted in 2005. Proposals for a "mini-PURPA" in the form of a national renewable energy standard appear to have stalled in Congress.

What's the future for the true independent power company? Will the trend lines start to reverse with relatively more new generation being put into rate base?

Four top US power industry veterans debated these subjects at the 22nd annual global energy and finance conference hosted by Chadbourne in Utah in June. The debaters are Michael Schwartz, at the time senior vice president of Duke Energy Ventures and now CEO of New Wave Energy, Larry Kellerman, CEO of Quantum Utility Generation and a former managing director for power and utilities at Goldman Sachs, Robert Hemphill, president of AES Solar, and Jonathan Bram, managing director of Global Infrastructure Partners. The moderator is Ken Hansen from the Chadbourne Washington office.

MR. HANSEN: We have assembled an eminent panel to debate the issue. Speaking first in favor of the resolution that the independent generator model is dead is Michael Schwartz.

/ continued page 2

IN OTHER NEWS

LARGE BATTERIES at wind and solar projects qualify potentially for investment tax credits.

The Internal Revenue Service said in a private ruling made public in late October that the owner of a new wind farm can claim a 30% investment tax credit on the cost of a large bank of lithium ion batteries installed at the project. The IRS decided the storage device is part of the generating equipment since it operates essentially as a knob on a motor by helping to control how much electricity from the wind farm is fed into the grid. The ruling is Private Letter Ruling 201142005.

/ continued page 2

IN THIS ISSUE

1 Is the US Independent Generator Model Dead?
12 Chinese Solar Cells May Face US Import Duties
14 Treasury Cash Grant Update
18 Winds of Change In South Africa
24 Financing Rooftop Solar Projects in the US
33 Latin America: How Big an Opportunity For Renewables?
39 Negotiating With Chinese Lenders
41 Policy Quagmire: What Next?
44 US Inbound Investment Strategies For Renewable Energy
50 How The Arab Spring Is Affecting The Project Finance Market In The Middle East
54 Oil and Fuel Companies Under Increasing Pressure to Stop Iran Business
57 Battle Over Power Contracts
63 Practical Advice: Wind and Solar Projects on BLM Lands
66 Environmental Update

Independent Generators

continued from page 1

Ability to Innovate

MR. SCHWARTZ: My comments break down along two lines.

In the renewable energy sector, demand is driven by state renewable portfolio standards. Candidly, I do not see state RPS targets driving "inexorable" and "sustainable" growth in demand. One need look no farther than what happened in Connecticut last year and what is currently happening in Maine where opponents of RPS targets are attempting to roll them back. The recession and growing concerns about economic development and local job creation are changing the dynamic around state RPSs.

Turning to the rest of the independent power sector, the challenge of procuring power contracts is a manifestation of a much deeper and more fundamental dysfunctionality afflicting competitive power markets that calls into question the decision to deregulate electricity generation. I know this is an incendiary assertion to make before this august group, but, hopefully, you will give me a couple minutes before you start throwing things of increasingly heavy weight at me.

The US electric utility industry is bifurcated into two distinct segments: regulated and unregulated entities. In contrast to five years ago where independent generator NRG Energy was trading at, let's say, a price-to-earnings multiple of 16, we now see materially higher PEs for regulated utilities than for independent generators. Look at the numbers. Southern and Duke are trading about 17. NRG is at 9. AES is outperforming in the nonutility sector at about 11. This has led to an equity premium for regulated utilities, and recent M&A transactions are evidence of this flight to quality and the premium on the equity side for regulated utilities.

This flight to quality can also be seen in the debt markets with a current spread between regulated utilities and nonutility generators in terms of cost of debt.

Why is this happening?

Independent power companies no longer can provide low cost power to the market and customers.

Outside of the renewable energy sector, who are the innovators? Who is deploying capital across the US energy spectrum in advanced commercialization of new technology? It is not the independent power companies. Duke Energy is building one of the first integrated-gas combined-cycle power plants in the United States of America. We are completing an ultra-supercritical coal facility, moving on nuclear, making commercial-scale investments in the smart grid and deploying capital around electric vehicles and distributed generation. The innovation and the deployment of capital in new technologies are in the regulated utility sector, not the independent power sector. We are operating under long-term integrated resource plans that promote technology development and fuel diversification in support of long-term customer needs and in an effort to drive down customer costs.

Look at the competitive markets. There is significant doubt about the ability of these markets to attract the capital required to build new gas peakers, yet alone intermediate or base-load generation. For the most part, states and competitive markets have abandoned the RFP process. There is no regulatory oversight to promote long-term development of technology and fuel diversification, and there are key questions around the ability of competitive markets to meet the long-term needs of customers.

MR. HANSEN: Speaking in opposition to the resolution is Jonathan Bram.

Industry Cycles

MR. BRAM: Let me provide some historical context. Why were independent power companies able to build such a high market share by 2003? What changed? What does it mean for the future?

There was a boom in construction of new power plants by independent power companies from the late 1990's to 2003 when the sector reached a plateau. Two factors contributed to this. One was that after a decade of virtually no new construction, there was a need for significant new generating capacity, and the independent generators built it. That was when there was a four-year backlog for new gas turbines that we thought we would never see again until we saw the four-year backlog for wind turbines. So there was a period of lots of new construction.

It was also a period when utilities were being forced by their regulators to divest massive amounts of generating assets.

These trends did not end with Enron. They ended with the California energy crisis. They created a massive increase in independent ownership of generating assets, which came to a screeching halt around 2001 or 2002 because of the financial crisis, the recession that followed the terrorist attacks on September 11, 2001 and the halt in further deregulation that was in part a reaction to the California energy crisis.

From that point forward, the market penetration by independent power producers remained static, which is logical because the people in this room are highly economic. From around 2001 to today, market prices have not justified new construction. Market prices basically justify discounts to new construction of anywhere from 40% to 50%, which is why you saw secondary sales of relatively new power plants in the period 2003 to 2004 going at 30% to 40% of construction costs and now edging up somewhat to the 40% to 50% range. These projects are not retaining full value because of the big reserve margins and excess capacity in many parts of the country and, if there is one thing about the folks in this room, they do not build things that the world does not need.

This condition will not last forever. Life is long and cyclical and, right now, there is no part of the country where market prices justify new construction. There are episodic places where utilities can build new power plants because they are able to convince their regulators that an additional rate base investment makes sense. A lot of the technological innovations that Michael Schwartz talked about — from IGCC plants to nuclear — do not make sense on paper. Therefore, it should not be surprising that folks who need nonrecourse financing to build, and who actually have to justify something in the four corners of a spreadsheet, are not building today.

That said, there are large parts of the country where people think there is value to switching to renewable energy. When we get to a position where we need to add new generating capacity, I think you will see much more support for renewable portfolio standards.

As we stand here in the middle of a deep recession, I would say that it will be a few years before supply and demand move back to equilibrium. The skills that the independent developers have are unquestionably valuable to society. Everyone loves the irrational optimism of developers. When it comes time to site and build something on a cost-effective basis, there is no doubt that the entrepreneurship will add value. On the other hand, when it comes to build a nuclear power plant, I don't think these skills will add enough value, because I don't think you could ever justify such a power plant without the safety net of the regulated ratepayer who will pay for the mistakes or benefit from the success, whichever happens.

What is most interesting to me is to think about where we are now. As we get to a point where supply and demand move closer to equilibrium, will this partially deregulated system that we find ourselves in provide enough reward to independent generators to build new power plants? / continued page 3

IN OTHER NEWS

The storage device will also be used to provide regulation services to the grid. However, less than 3% of the charge for the device on average is expected to come each year from the grid. The project is expected to get roughly a 20% boost in revenue from the device through both price arbitrage and regulation services.

The storage device is on the low side of the main transformer that the project uses to step up the electricity to transmission voltage. It is owned by the same legal entity that owns the wind farm. It helped that the device is not treated as transmission equipment for regulatory purposes by the grid.

The IRS has another ruling request pending involving a large battery installed at a wind farm that is already in operation. The battery in that case is expected to get roughly 15% of its annual charge from the grid.

The agency is still working out where to draw the line on tax subsidies for storage devices at renewable energy facilities.

MOST CALIFORNIA SOLAR PROJECTS remain exempted from annual property taxes, even if they are transferred during construction, according to draft guidelines the State Board of Equalization issued in mid-October.

California collects annual property taxes that are generally at least 1% of the assessed value of power projects. The actual rate varies by county. However, a project must be assessed first, and there is a one-time exemption for solar projects from assessment. Ordinarily, a project is subject to final assessment at the end of construction. Transferring a project also triggers an assessment.

Questions have come up whether the one-time exemption is used up if a solar project is transferred during construction.

The State Board of Equalization said it is not. However, utility-scale projects may not be able to benefit from the exemption. Most projects are assessed at the county level. The new guidelines do not apply to / continued page 5

Independent Generators

continued from page 3

That is a problem. In parts of the country, states are basically saying "No." That is what Maryland and New Jersey are saying. They are trying, in essence, to exercise monopoly power by signing contracts to add some capacity to keep the market fully supplied, so that the only place you will ever see equilibrium power pricing is in a market study as opposed to the real world. That means it will be very difficult for independent developers to add new capacity.

Independent generators produce 42% of US electricity. The percentage has not changed since 2003.

However, where there is a demand — for example, for renewables in states where utilities are willing to sign power purchase agreements — independent developers have enormous penetration because of their energy, effort, hard work, skill and capability. The good days will return. However, in the meantime, if you are looking to build new generating capacity that is not needed because reserve margins are still in the mid-20% range on a national basis, it does not matter whether you are an independent generator or a regulated utility. New growth will have to wait until we emerge from the recession and there is new demand for electricity.

MR. HANSEN: Now an opening statement in favor of the resolution from Larry Kellerman.

Dependent Power Producers

MR. KELLERMAN: The heyday of the independent power producer has passed. The IPP business model that justified the independent power industry and allowed it to flourish no longer exists. We have moved from a world in which independent power producers existed in a win-lose relationship with utilities. IPPs have been eclipsed and are being replaced, sometimes in the same company, with DPPs.

The power producers of this era and the future are going to have to function in a more positive, constructive and dependent relationship with the utilities of North America than they have had to do in the past.

Let me take you through the three eras of the non-utility generation business to give you a sense for why that is the case.

The first era began in 1978 and lasted through the mid-1990s. It was the PURPA era. It was the era of QFs. The era was characterized by above-market contracts shoved down the utilities' throats against their will and whose legacy is a series of both strange relationships and stranded costs with which many utilities are still wrestling today. The objective function of the IPP sector during that period was to create the highest spread between the sometimes rightfully constructed, sometimes artificially constructed, characterization of avoided cost under PURPA versus the cost structure that they were able to enjoy. The result over time was a legacy of long-term contracts binding utilities to buy electricity at above-market rates. These were highly lucrative power contracts with highly attractive returns, and they turned a number of early movers in the industry into billionaires.

That was the first era of the IPP industry, the PURPA era, and it formally died in 2005. It really started to die in the mid-1990s when PURPA contracts started to tail off. Taking its place in the mid- to late 1990s and somewhat peaking in the early to middle part of the last decade was the independent merchant energy industry.

The ascendency of the merchants took place in a frothy period of unrealistic market forecasts and unrealistic lending practices of the financial community. Wherever you had a section of 36-inch gas pipeline near a 345-kv line, someone was building a gas-fired power plant and getting it financed. At the same time, there were many auctions in which utilities were forced to divest their older generating assets, and tens of billions of dollars of capital were pumped into the sector. Since then, tens of billions of dollars have been lost through a series of well-known bankruptcies and, today, these merchants are engaged in consolidation and cost reduction rather than robustly looking to grow. That was phase two of the IPP industry.

Now I would like to bring you to phase three, which I believe we have started to enter. It is an environment in which the interests of non-utility generators are going to be much more tightly aligned with the interests of the regulated utilities. Unlike the last two eras, where the objective function was to increase price, the objective function of the new era of DPPs is to reduce your costs enough to be able to compete on price with the regulated utilities. Without legislation forcing utilities to do what they sometimes did not want to do and without the flawed market forecasts and flawed lending practices of the past, the non-utilities of this era can no longer afford to be truly independent.

Therefore, the era of independent power producers is over. The era of competing with utilities is over. The era of viewing utilities as true customers or as true counterparties is upon us. It is an era not of independent power producers but of dependent, co-dependent or inter-dependent power producers.

MR. HANSEN: Our final opening statement will be from Bob Hemphill.

True Innovators

MR. HEMPHILL: The Chadbourne slide that indicates that the market share of independent generators has remained fixed for the last eight years is not surprising. If no one is building anything, why would there be a shift in market shares?

I find it unconvincing evidence that the independent generator model is dead.

The other piece of data that I find interesting is that if you look at what actually *has* been built in the United States over the last four or five years, it has been at least half renewables and, in the renewables sector, a healthy 90% to 95% of projects have been built by independent generators. Why is that? Is it because utilities are models of innovation? Is it because utilities are nimble and fleet of foot? Is it because utilities are able to leverage their projects at 85% and thus have a lower cost of capital? Those are not the utilities that I know.

If you look around the world, you will see, time and again, instances where the competitive landscape for innovative and new technologies has favored independent generators. For years and years, Eskom in South Africa was probably considered the most difficult utility in the world to / *continued page 6*

IN OTHER NEWS

projects that are assessed at the state level. Projects that are 50 megawatts or larger in size are assessed at the state level if they are owned by "electrical corporations," meaning power companies — or affiliates of such power companies — that make retail sales of electricity rather than sell all of their electricity at wholesale.

The new guidelines are also unclear about whether a change in ownership of the solar company during construction or a sale-leaseback of a project after construction is ignored. Most sale-leasebacks are done within three months after a project is put into service.

The SBOE is accepting comments on the guidelines through November 23, 2011. A public meeting will be held in January 2012.

FEDERAL BANK REGULATORS released 298 pages of regulations in October to implement a "Volcker rule" that is supposed to bar banks from engaging in proprietary trading and taking equity positions in private equity and hedge funds.

The regulations are not expected to prevent banks from investing as tax equity participants in renewable energy projects, according to Adam Gale, a bank regulatory lawyer in the Chadbourne New York office.

Gale said the key for a bank participating in a partnership flip transaction is it must have an ownership interest in the operating company itself or in a parent holding company whose only assets are majority interests in operating companies. It is important that the bank's investment be in an operating company as opposed to a "covered fund." If the bank were to invest in an intermediate entity that is not the operating company (or is not a parent holding company whose sole asset is a majority interest in an operating company), then "the intermediate entity would probably fall within the definition of a 'covered fund,' and the Volcker rule general prohibition against bank investments in covered funds would apply," Gale said.

Proprietary trading, which is also banned, is defined in the new / *continued page 7*

Independent Generators

continued from page 5

deal with, and that was quite an achievement, given utilities in general. Unfortunately, Eskom — nimble, fleet-footed and innovative — was unable to keep the lights on in South Africa, which is kind of what they teach you on day one in utilities school: "Do not let the lights go out." Consequently, the South African government has now excluded Eskom from participating in the upcoming renewable construction proceedings, and has forced it to serve only as the contracting party.

The Long Island Power Authority recently released a 2,500-megawatt RFP. The company is not crazy. If it thought it was better at generating electricity, then it would be building new power plants. Southern California Edison announced that it would do 500 megawatts of rooftop solar; it stopped after about 130 megawatts with the admission that it was not any good at this. The argument that utilities really know how to do things and will out perform, out think, out play, outwit and out run independent power producers is flawed.

I *am* willing to cede the territory of nuclear power. When I look at the most recently published Duke numbers, which were flawed in the way they calculate construction interest, I still get something like $7 million a megawatt. David Crane was quoted as saying that, for NRG, the first couple of nuclear units will cost $10 million a megawatt, but once they are built, the company will have learned a lot and, therefore, be able to get the price down.

My company, AES, has come to an agreement to purchase Dayton Power & Light, which may undermine my arguments, but if there is such a high quality premium on utilities, how come we are picking them up at a 13% premium to what their current trading is, and how come that is cash-and-earnings accretive to AES, which is trading at this remarkably low multiple? That does not look to me like a signal that Dayton Power & Light is benefiting from the flight to quality that my colleagues have mentioned.

In conclusion, I guess I would say I really wish that you could still get a standard offer four contract just by showing up at Southern California Edison's offices. That was great. And I really wish that all those Japanese banks were still around that would give you 100% debt financing. That was fabulous. I agree those days are not likely to come back, but the fact remains that the IPP industry has consistently shown itself more creative, more willing to take risk and to profit from those risks, more innovative in financing structures, and a much more rapid adapter of technologies *that make sense*; nuclear and integrated-gas combined-cycle project do not. A colleague of mine characterized IGCC as "combined cycle at $5 million a megawatt," and that price has probably gone up since the start of this panel.

Whether the heyday is over depends on how you define "heyday," but I see every possibility that independent generators will maintain a dynamic and interesting share of the generation market in the United States.

MR. HANSEN: Does any of you have anything you would like to add to your opening statement?

The Texas Example

MR. KELLERMAN: In support of our contention that the heyday of the IPPs is over, I give you Texas. Five, six, maybe even seven years ago, power in Texas cost retail consumers less than the national average, while gas prices were in the very high single digits to low double digits per mcf. Today, gas is barely $4.50 an mcf; yet Texas retail prices are above the national average.

Why is that?

The available generating capacity is still well above peak loads. There has not been a lot of new construction. There is a competitive power market and there are competitive retail suppliers that are supposed to bring competitive dynamics and drive down prices. That has been an abject failure by every mathematical or objective standard.

What we have created is an environment in which once-strong utilities with good credit ratings, Texas Utilities and Houston Lighting & Power, are now either on the verge of bankruptcy or fundamentally non-existent, replaced by a plethora of very high-cost retail energy distributors and a large number of independent generators who do not offer any cost efficiencies and whose objective is to increase the wholesale price of power. What we have in Texas is something that is diametrically opposed to the promise of the wonderfully-sounding, attractive notion of competition bringing down prices. Instead, we have a flawed market structure in which utilities have taken a back seat to a series of competitors whose interests are not in keeping power prices low or keeping the lights on.

MR. HANSEN: Bob Hemphill, any response?

MR. HEMPHILL: Yes. A comparison of the kind that Larry Kellerman makes, while intriguing, says nothing about what prices would have been had the old triumvirate of Texas Utilities, Houston Lighting & Power and Southwest still been in charge. The fact that prices are above the national average is unconvincing because we do not know what would have happened in the alternative.

MR. HANSEN: Michael Schwartz?

MR. SCHWARTZ: I think we are on two different wave lengths. I am known as an unrecovered developer. I agree that independent generators have been able to deploy projects, new technologies and innovative commercial constructs that would never have been fully deployed by the regulated utilities. My argument is a strategic one. The regulated utility model in the United States provides a vehicle for long-term planning, for goal-setting, and for establishing some kind of construct that balances long-term and near-term objectives. That is absent in the independent power market. What I am arguing is that what replaced the regulated generators is strategically flawed and dangerous. We have to look at the relationship between the IPPs and the regulated utilities in a different way.

MR. HANSON: Jonathan Bram?

MR. BRAM: I have two observations. First as it relates to ERCOT and Texas, there is no evidence of a huge windfall for wholesale generators. To the extent retail rates are high, it is probably because they are under-regulated. The problem is between the bus bar and the customer. Just look at the prices that people are paying for combined-cycle power plants in ERCOT. There is no evidence that in that very liquid market people are getting some huge premium over replacement cost for power plants. The top of the range today is probably low for similar assets in other markets. I agree with Mike Schwartz that in a lot of these markets, there is no means to assure adequacy. ERCOT is probably the place where supply and demand are coming closest to equilibrium; minor issues can cause large upsets, like in February and August when there were outages and brown outs.

Second, it would be very interesting to see what would cause someone to build a new merchant power plant in Texas. The day will come soon when more generating capacity is needed. I am not sure that market provides any incentive for anyone to build. The easy days of signing a standard offer contract with a utility, and then waiting a few years to see whether gas prices go up or down, are over. The days when utilities and public utility commissions would hand out real options to people, who would then wait to see which way they would go to make their $25 million, are behind us. However, there will definitely be a role for independent generators going forward because those are the people who are capable of actually building things at the least cost, which adds efficiency and is really important to our overall economic growth.

/ continued page 8

IN OTHER NEWS

regulations as short-term trading, meaning investing in positions held fewer than 60 days. If a bank makes a tax equity investment with the intention of selling all or part of the investment within 60 days, then it is possible that the investment could be considered proprietary trading.

POWER PLANTS THAT USE SOLID WASTE as fuel can be financed in the tax-exempt bond market.

The IRS made it easier in August for fuel to qualify as "solid waste."

Tax-exempt financing is normally reserved for schools, roads, hospitals and other public facilities. However, it can also be used to finance 13 other types of projects that are privately owned. One of the 13 categories is a "solid waste disposal facility." Tax-exempt financing has been used in the past under this provision to finance expensive pollution control equipment at the back end of large coal-fired power plants. It has also been used to finance equipment through the boiler at the front end of power plants that burn culm or gob, two forms of waste coal. Culm is dirt that was brought up many years ago from underground mining of anthracite coal and left in a pile above ground. The dirt contains coal residues that can be removed through modern processes. Gob is similar material from underground mining of bituminous coal.

In the past, material qualified as solid waste only if it was unused, unwanted or discarded material that had no value in the place where it is located. Thus, if there was a local market in culm or gob, the fuel did not qualify as solid waste. Power plant owners would pay to have the culm or gob transported or processed, but not for the underlying material.

The IRS has dropped the need to show material has no value. Material now qualifies as solid waste if it has been used previously or is considered residue from an agriculture, commercial or industrial process. However, material qualifies as a residue only if its market value is less than the value of the products or service from which the material is left over. Animal manure is considered "used" material.

/ continued page 9

Independent Generators

continued from page 7

MR. HANSEN: Bob Hemphill, do you have a question for Larry Kellerman?

Flawed Markets?

MR. HEMPHILL: I thought we were talking about independent generators. Larry, both you and your colleague have eloquently and persuasively indicted something called the "competitive market system," which may be flawed, but I don't think that is the fault of the independent power industry. We are on the wholesale end of the business, and you are talking retail.

Will the trend lines start to reverse with relatively more new generation being put into rate base?

MR. KELLERMAN: Good point. Let me refocus from Texas to New Jersey and Maryland, two states that your colleague, Jonathan Bram, said are tilting away from a purely competitive market. The fact is that New Jersey and Maryland have been forced into doing what they are doing because the independent power community was not motivated enough to take actions that would align generation with demand. Is it the fault of the IPPs or of the market structure? The fact is that action was not being taken. The problem with market signals in PJM is that you worry about being kicked in a place you don't want to be kicked. When you relieve a constraint, the resulting forward market price, after that constraint is relieved, is now dialed back to market equilibrium.

What you have is a market structure that produces the opposite of what society wants. Society wants relief from constraints. If I am a rational independent generator in the PJM market, what do I want? I want the preservation of constraints. That is the only way I am going to get high prices. The market structure makes no sense.

What Maryland and New Jersey are saying is that they have to do something to protect their consumers, and that means they have to dictate where, when, how and who builds new generating capacity. The market forces are not doing it. This is an example of where independent generators are not stepping up to do what the brilliant Harvard-trained economists who came up with the whole notion of capacity markets failed to foresee when thinking through how their models would work in the real world.

MR. HANSEN: Michael Schwartz, your question for Jonathan Bram.

Natural Owners

MR. SCHWARTZ: Jon, I truly get your point about the dynamic of the current market. Do you see pressure or an incentive to move ownership of generating assets from publicly-traded companies that are focused on near-term earnings to privately-held enterprises who can manage through volatility, and particularly to infrastructure funds such as yourselves?

MR. BRAM: I think funds like ours have a role to play. An independent generator business is a challenging model to conduct in a public company. Bob Hemphill's company is one of the few that have survived. There are always about five, but the list turns over from year to year. When this conference first started, it was O'Brien Environmental Power and Catalyst Energy. Think of all these companies that existed for a time, but don't any longer, because the public market does not appreciate NPV value creation. It is looking for growth in earnings per share. It is looking for pops. The reality is we are in a long-cycle business, so a company like AES could build five projects in two years, and then nothing for 10, because it is being rational; there is no demand for additional generation. It has always been a challenge for the public markets to value these companies fairly.

MR. HANSEN: Jonathan Bram, do you have a question for Mike Schwartz?

MR. BRAM: I think you pointed out that utilities currently enjoy a cost-to-capital advantage. The independent power business was built on having a cost-to-capital advantage that was based largely on more leverage — utilities were at 50-50 debt to equity while independent generators had 80% leverage. When they got to scale they could even have debt at a holdco level on top of debt at the project level. This gave them a lower cost of capital on an all-in basis.

This is no longer true. Lenders are more risk averse. Utility trading values are near an historic peak in terms of price to earnings, which is typical of a period when people are frightened.

If you fast forward to a world where suddenly we need to build, which means the recession is over, demand has caught up with supply, and interest rates are at more normal levels, Treasuries will no longer be at 3%. They will be at 5% to 7%. If the market responds to all the paper the US government has printed to get out of the recession, the rates could be much worse. Do you agree that in such an environment, independent generators are likely to have a cost of capital that is equivalent to that of utilities?

MR. SCHWARTZ: I think there is another factor at work called a "flight to quality." Certainly I can see a period when there is a need for significant new generation, but the question as coupon rates rise is what will happen with the spreads. The regulated utility construct provides greater certainty for cost recovery, thereby mitigating risk and thereby driving down coupon rates. Given this, I am not sure that independent generators will be on a level playing field with utilities. Going forward, the question will be what part of the spectrum of new opportunities should be funded and owned by regulated utilities, who have a service obligation and are assured recovery of their capital costs, versus independent generators, who have neither.

MR. HANSEN: Larry Kellerman, do you have a question for Bob Hemphill?

Migration to Utilities

MR. KELLERMAN: Bob, your company has been one of the most durable, successful independent generators in the world. AES created a business model several decades ago that has been proven to be not only viable, but also resilient and flexible.

AES started building cogeneration facilities in the early days of the independent power industry that are still generating value for your firm. It migrated into the merchant market, acquired power plants being divested by utilities and was successful in that business model. Isn't it a statement of both your success and flexibility as a business as well as how the market has dramatically changed from the classic independent generator model that AES has been largely / continued page 10

IN OTHER NEWS

Virgin material is never a solid waste. Hazardous and radioactive wastes do not qualify.

The equipment at a power plant that uses solid waste as fuel qualifies for tax-exempt financing only up to the point where the first marketable product is produced. In most power plants using waste, that first product is steam. Therefore, tax-exempt bonds can only to be used to finance equipment through the boiler. The power train does not qualify.

At least 65% of the fuel used in the power plant each year the tax-exempt bonds are expected to be outstanding must be solid waste. If the actual percentage dips below 65% in a year, then the bonds would have to be partially refunded. However, if the dip is caused by events outside the control of the plant operator, then he can wait to see whether he is above 65% in each of the next two years and add the excess in each of those years to the percentage in the bad year to get above the threshold. The annual testing does not start until the power plant is not only in service, but also is operating at close to its nameplate capacity.

The new rules apply to tax-exempt bonds issued on or after October 18, 2011.

A MUNICIPAL POWER PLANT can be financed partly in the tax-exempt bond market, the IRS said, even though a private power company operates the plant and takes part of the electricity under a long-term contract.

This may open the door to some new financing strategies for projects where a municipality is prepared to take only part of the electricity output.

The IRS said in a private ruling made public in July that a municipal utility could use tax-exempt bonds to pay the cost of new power plant that the municipal utility plans to own. The utility will let an electric cooperative operate the plant and sell the coop a share of the power under a long-term power purchase agreement. The IRS said the municipality could use tax-exempt financing for a fraction of the plant cost. The fraction is the / continued page 11

Independent Generators

continued from page 9

focusing its new investments on acquiring utilities — first, Indianapolis Power & Light and, now, Dayton Power & Light — and building other power plants with long-term output contracts with utilities as opposed to really being in the competitive markets?

MR. HEMPHILL: That's fair, but honestly, we had a whole hour of discussion about, "Why is it so hard to get power purchase agreements," which was fine, although somewhat self-reverent. The real question is: how can it be that there are other industries in the world that actually make things and sell them to people and, unbelievably, do not have long-term contracts? That's probably true of almost every other industry in the world. Many of them have high capital costs. Many of them have variable fuel costs. Many of them have technology challenges and yet, somehow, those companies, with the exception of the automobile industry, seem to survive, and many of them actually thrive and profit.

So I am a little mystified about why we all seem to think that it is impossible for us to do business without the solace and comfort of a long-term power contract.

Now, I would be the first to tell you that if I had the choice, I would absolutely much rather have a long-term offtake agreement with a monopoly provider with high credit. It is a terrific business model. But I do not see what should prevent the business model from moving more toward a merchant-based model. The argument, "Well, that will never support the construction of new capacity," just can't be right. It supports new capacity in every other industry in the world except this one.

MR. HANSEN: We have reached the end of our debate. Each of you will have about a minute to make a closing statement, in the same order as the opening statements.

Closing Summaries

MR. SCHWARTZ: First, let me apologize about the distracting proposition regarding re-regulation, but my reality is that politicians are loathe to address strategic issues that have a time scale well beyond the next election. Second, there is no pressure to change policy or regulatory direction in a falling or stable price market, which means nothing will happen in the near term. Third, unfortunately, political action in this country is derived from crisis, and the question in my mind is whether we are on the edge of an impending crisis.

If we are fortunate to have a sustained economic recovery, and there are 15 to 25 gigawatts of coal retirements in the northeast and mid-Atlantic states, then what happens? Is it another California-like energy crisis if our capacity markets are unable to respond? Could we see a federal clean energy standard that would create demand for clean energy for the foreseeable future? Could we see more states moving in the direction of Maryland and New Jersey, with probable litigation and controversy with the incumbent utilities, leaving the market in limbo? The answer is probably a little of all of the above. It is all quite vexing.

Winston Churchill said that an optimist is an individual who sees opportunity in every difficulty, and a pessimist sees difficulty in every opportunity. I remain optimistic that notwithstanding our inability to address these issues systematically, we will find a way as a nation to come together behind some kind of integrated, comprehensive national energy policy.

MR. BRAM: Clearly it is a difficult time for the independent power industry. It is difficult to earn a reasonable rate of return in a market that still has excess capacity. The greatest value independent generators have to offer is in developing new generation on the most cost-effective basis, but there is not an aching need for that. I think we are unlikely to have any crisis. Remember that electricity demand grows, in a good market, at a very slow pace of about 75% of GDP growth. For us to have a crisis would be a high-class problem because it would mean that the economy is growing dramatically. I think it is equally certain that we will never get what Mike Schwartz just said: a far-reaching and well-constructed energy policy.

I remain convinced that when the need is there for new capacity, independent developers will answer the call and will get a reasonable amount of market share. Certainly utilities will continue to add at a great pace; they have an obligation to serve. They have first claim on the customers. They have the support of their regulators, and if they build something a little bit early, it will not be uncomfortable because they are assured of earning a return on rate base. It is challenging today for independent generators, but the independent generator model will remain a viable business model.

MR. KELLERMAN: When we set about, less than a year ago, to name my company, we sat down with our sponsors and asked, "How do we want to position ourselves in the market?" We called ourselves Quantum Utility Generation. We consciously used the word "utility" in the name. The proposition of my business and of our side of this debate is not that you have to be a utility to generate power, but that we do not believe the PURPA and merchant business models of the past are durable, sustainable, profitable, viable or desired by society any longer. We believe a new model, the dependent power producer or DPP model, is the right model for the future, where we recognize our dependency on the utility sector.

We recognize the mutuality of objectives. We are not creating a win-lose situation where one side is trying to charge as much as it can and the other is trying to pay as little as possible. We are not trying to create or perpetuate constraints where they should not exist, but trying to relieve constraints and being paid appropriately for relieving them. We are proposing on our side that the model that independent generators have deployed in the past is history. There has been an evolution of the business models of *both* utilities and independent generators to a new, better and more durable model, where independent generators can work collegially with utilities.

MR. HEMPHILL: One of the early guys who promoted renewables was a gentleman named Amory Lovins. He was criticized for promoting them at a time when renewable technologies were frighteningly expensive, and Amory used to say that it was inherently a good idea, but at the same time, he was not there to defend bad engineering. I feel a little bit the same way. I am not here to defend bad market structures, because they are inherently indefensible. I also agree a hundred percent that anybody who has a power contract with a utility is not independent. We know that. If you were independent, and you were making electricity, where did it go? It had to go somewhere.

The point is dependency has been at the very core of the industry since the beginning.

The argument for the survival of the industry is that it has demonstrated an interesting ability to take more risk, to be more innovative and, consequently, to be more highly rewarded for taking risk in circumstances where the regulated nature of utilities does not reward them for taking those kinds of risks. I do not see that changing. I think we will continue to have a hybrid system, and the various independent power companies will do well or less well, depending on how smart and quick and clever they are. And at every conference that we have with Chadbourne for the next 22 years, we will continue to complain about how hard the business is. ◎

IN OTHER NEWS

expected share of the electricity that the municipal utility will retain over the term of the bonds as a percentage of nameplate capacity,

Tax-exempt bonds usually cannot be issued for projects that are put to more than 10% "private business use." It is a private business use to sell the output to a private party, including an electric cooperative, under a bilateral contract. It may also be a private business use to let a private party operate the plant. However, in this case the IRS said the fact that the coop was the contract operator was not a problem because the municipal utility planned only to reimburse the coop for the actual costs to operate and then only for a share of those costs equal to the share of plant capacity retained by the municipal utility.

The ruling is Private Letter Ruling 201128010.

A ROOFTOP SOLAR SYSTEM may qualify only in part for an investment tax credit, the IRS said.

Many rooftop systems require a membrane underneath the solar panels that doubles as a roof. IRS regulations have two conflicting rules when it comes to such membranes. One is that investment tax credits cannot ordinarily be claimed on the cost of "buildings and structural components." The other is that even though something looks like part of the building, it can be so specially engineered as to be part of the equipment being installed on top of it. The IRS said it is prepared in such cases to allow an investment credit on the membrane only to the extent of the incremental cost above what a membrane that serves solely as a roof would cost.

The IRS position is in Private Letter Ruling 201121005. The agency released the text in June.

It is not clear the conclusion is correct.

Congress said when it first authorized an energy tax credit for solar equipment (on which the current investment credit is patterned) that such equipment qualifies for a tax credit "without regard to whether the equipment [is] a structural component of the building."

There are two tax credits for rooftop solar systems. A system put to business use qualifies

/ continued page 13

Chinese Solar Cells May Face US Import Duties

by Keith Martin and Samuel R. Kwon, in Washington

Anti-dumping or countervailing duties could be imposed on photovoltaic cells imported from China starting this fall at the earliest, but more likely after a date in the spring or summer 2012, under a trade complaint that SolarWorld and six other US solar panel manufacturers filed against Chinese panel makers charging that Chinese solar cells are being dumped in the US market and are benefiting from illegal export subsidies.

The complaint only applies to crystalline solar cells. It does not apply to thin film or other solar equipment.

A table included as an exhibit to the complaint lists the dumping margins, or the discount at which Chinese panels are allegedly being sold below "normal value" expressed as a percentage of the actual sales price. Examples are 159% for Trina panels, 184% for Suntech and 233% for Yingli. The pattern in such cases is to allege very high margins that get reduced during the investigation.

A separate table lists all the US customers who have been identified by the petitioners as buying Chinese panels.

The US panel makers petitioned US trade authorities for relief on October 19.

The Commerce Department has 20 days to decide whether to investigate. This can be extended by another 20 days if the case is viewed as complicated. Once an investigation starts, the Commerce Department has 65 days to decide whether there are grounds for imposing countervailing duties and 140 days to decide whether to impose anti-dumping duties. These deadlines can be extended to as long as 250 days for countervailing duties and 310 days for anti-dumping duties for cases that are extraordinarily complicated and involve upstream subsidies of components that take time to trace.

At that point, the Commerce Department makes a preliminary decision on duties.

Countervailing duties are supposed to match the subsidies from which Chinese panel manufacturers benefit. If anti-dumping duties are imposed, they are the difference between the "normal value" of the panels and the price at which the panels are being sold in the US market. The law is unclear currently whether both types of duties can be imposed on products shipped from a non-market economy. The issue is before the federal courts.

Duties are imposed on the importer of record. Thus, in cases where a Chinese solar panel company sells its product in the United States through a US subsidiary, the US subsidiary must pay the duty.

Once a preliminary decision is made to impose duties, then importers must post a bond or other security. Duties would normally apply to solar cells imported after the preliminary decision. However, they can be imposed up to 90 days earlier if there is a "critical circumstance." It would be unusual to have such a retroactive imposition. An example of a critical circumstance is where there is evidence that Chinese solar panel manufacturers are accelerating exports to the United States in anticipation of an adverse decision. The fact that US solar developers are rushing to start construction of projects this year to qualify for Treasury cash grants could complicate the issue.

The US government must find two things to impose duties. One is injury to a US industry. The International Trade Commission makes a decision on injury. The other is evidence of dumping or illegal export subsidies. This is a Commerce decision. The two agencies work on parallel tracks. The ITC must make a preliminary determination on harm within 45 days after the petition is filed.

Commerce has another 75 days after its preliminary decision to make a final judgment. The ITC has another 45 days after Commerce acts to make a final decision on injury.

After the ITC final decision, then bonds and other security are liquidated and duties collected.

Cases frequently land on appeal in the US Court of International Trade. There is no suspension of duties during an appeal. It is more common to see the amount of duties appealed than the decision about industry harm, since small changes in amount can add up to large dollars.

The seller cannot reimburse the buyer for the duty. Any such reimbursement must be paid to the US government as an additional import charge.

It does not matter at what prices competing solar panels are being sold by US manufacturers. Thus, for example, if a US solar developer can buy panels from China at $1 a watt and from US suppliers for $1.25, but Commerce decides the "normal value" is $1.50, then an anti-dumping duty of 50¢ would be imposed on the Chinese panels. The normal value is normally determined by looking at the price at which the foreign manufacturer sells the panels in its domestic market. However, in the case of a non-market economy like China, the normal value is determined by looking at panel prices in a third country. The petitioners in the case propose using India.

Many Chinese companies sell their products through US subsidiaries. In such cases, the "export price" on which the duty is collected is the resale price to the ultimate US customer less certain statutory reductions. The price is reduced by the cost to move the panels from the factory in China to the United States, by any normal Customs duty (but not the anti-dumping or

> The US could impose anti-dumping or countervailing duties on Chinese solar cells starting next spring or summer.

countervailing duties) and by certain other costs of the US subsidiary to make the sale. Thus, for example, if the resale price is \$1 a watt, the normal value is \$1.50 and it costs the US subsidiary 15¢ to make the sale, then the anti-dumping duty would be \$1.50 - (\$1 - 15¢) = 65¢. If the Chinese parent reimburses the subsidiary for the anti-dumping duty, then that reimbursement would have to be paid to the US government.

US customers would continue to pay \$1 a watt in theory, but in practice the Chinese panel maker would lose money on such sales.

It could escape duties by supplying solar cells from a factory in the United States or a third country. However, enough value would have to be added in the US or the third country for the cells to be considered a local product.

The law is designed to allow no real political influence in decisions, although industry groups sometimes meet with government officials during the proceedings. Both Commerce and the International Trade Commission decide cases on the facts. The president does not have the option to set aside a decision. ◎

IN OTHER NEWS

potentially for an investment tax credit for 30% of the "basis" the owner has in the system.

The other tax credit is a solar residential credit — also 30% — for systems owned by homeowners. IRS officials say there is no reduction in the solar residential credit where solar shingles or tiles are installed, even though they also function as a roof.

Meanwhile, the IRS told a homeowner in another private ruling made public in August that a solar residential credit can be claimed on the incremental cost of a condensing unit installed to cool a home using electricity from rooftop solar panels. The IRS let the homeowner claim a tax credit on the cost to modify the condensing unit to run on solar electricity directly without having to run the electricity through an inverter. The homeowner was able to claim a 10% tax credit on the remaining cost of the condensing unit as an energy efficiency improvement to a building. The ruling is Private Letter Ruling 201130003.

The IRS is updating its regulations on when solar equipment put to business use qualifies for investment tax credits. The existing regulations date to 1980. The agency hopes to issue new regulations by June 2012. It is collecting comments in the meantime.

WIND FARMS IN PUERTO RICO and other US possessions qualify for accelerated US tax depreciation — and by extension, investment tax credits or Treasury cash grants — the IRS said in a private ruling.

However, the wind farm must have as its ultimate owners all US corporations or US citizens to receive the full subsidy. It is okay for such persons to own the project through a chain of limited liability companies or partnerships as long as all of the intermediate entities are "transparent" for US tax purposes.

Bringing in a local or foreign partner is a problem, unless the partner owns its interest through a US entity treated for US tax purposes as a corporation. It / continued page 15

Treasury Cash Grant Update

by Keith Martin, in Washington

Many US developers are rushing to start construction of renewable energy projects before year end so that the projects will qualify for so-called section 1603 payments from the US Treasury. The payments are normally 30% of the project cost.

Their strategies often involve taking delivery of equipment that will be used in the projects.

They may not know yet where the equipment will be deployed.

These developers will have to be careful next year when transferring the equipment or interests in the projects while the projects are still under construction. The ability to claim a Treasury cash grant may be lost.

The Treasury has made clear where lines are drawn in a series of meetings, telephone calls and emails in recent weeks.

In other developments, the Internal Revenue Service released an internal memo in October that claims the agency can audit cash grants that have already been paid on projects. The memo has not gone down well with some parts of the wind and solar industries.

The Treasury said on June 30 that it used a benchmark of $4 to $7 a watt for judging whether solar developers were claiming too high a value for projects put in service in the first quarter this year. Solar module prices have been falling since then.

An inspector general report posted to the Treasury website in mid-October about a grant paid on a large wind farm suggests the Treasury will pay grants on spare parts stockpiled to prevent downtime at projects is remote areas. The Treasury released five inspector general reports in October asking two wind companies and one solar developer to repay part of the grants that they received on five projects. The largest repayment claim is $2.1 million against a grant of $67.9 million

Construction-Start Issues

All remaining wind, solar, geothermal, fuel cell and other renewable energy projects must be under construction by the end of this year to receive a Treasury cash grant.

There are two ways to start construction. One is to take delivery of enough turbines, solar modules or other equipment this year to amount to more than 5% of the project cost. The other is to start physical work of a significant nature. Lenders and tax equity investors have shown a clear preference for the 5% test. The problem with the physical work test is that it does not require as much effort this year, so the Treasury requires the developer be able to show there was continuous construction after 2011. Many lenders and tax equity investors do not want to take the risk.

It is not enough for a developer trying to start construction under the 5% test merely to spend money in 2011. It must "incur" costs in 2011. That usually means take delivery of equipment, with one exception. The developer can pay for the equipment this year and count the spending as 2011 costs, provided it takes delivery within 3 1/2 months after payment. The payment must be for the specific equipment delivered and not a general milestone payment.

The Treasury has said a wind or solar company that takes delivery of a large number of turbines, solar modules or inverters this year, without knowing where the equipment will be used ultimately, can contribute batches of such equipment after this year to separate project companies and in that way seed multiple grandfathered projects. Enough 2011 equipment must be put in each project company to amount to more than 5% of the project cost.

Treasury has wavered whether the test is more than 5% of project cost or the amount the developer ultimately uses as its basis to calculate its grant on a project. Grants are normally 30% of the project cost. However, in some cases, grants are calculated on the fair market value after construction rather than the project cost. In such cases, 5% may be on the higher number.

Investors buying into a project or lenders foreclosing on a project after this year while the project is still under construction must be careful.

The ability to claim a Treasury cash grant will be lost if equipment or other project assets are transferred directly. Grandfather rights to a grant do not carry over in an asset transfer while a project is still under construction.

They carry over only if the investor or lender buys or forecloses on the project company — not the assets.

The Treasury does not want trafficking next year in grandfathered equipment. Some entrepreneurs have talked about stockpiling components, particularly in the solar market, and then selling them next year as "golden" inventory that will entitle the holder to a cash grant. This does not work. The Treasury is expected to be on the lookout for schemes where stockpiled inventory is dropped into special-purpose project companies and the project companies are sold as a way of selling inventory.

Any transfer of assets after this year potentially raises issues. However, a capital contribution by a developer to a limited liability company that the developer continues to own is not a problem. Treasury has also said that a normal tax equity transaction is not a problem — for example, where assets are sold and leased back within three months after a project is placed in service or an investor is brought into a project company that owns the project as a partner with the developer.

IRS Audits

The Internal Revenue Service released an internal memo in early October that suggests the IRS can audit cash grants on projects. The memo came as a surprise and has led to protests from some parts of the wind and solar industries.

Some forms of tax equity transactions allow grants to be calculated on the fair market value of the projects after construction rather than the construction cost.

The Treasury has sometimes pushed back on the values claimed, particularly in leasing transactions.

Developers have argued in meetings with the Treasury that the IRS would accept the values claimed in such transactions if an investment tax credit were claimed in place of a Treasury cash grant. They have appraisals to back up the values claimed. In addition, where the tax equity transaction is a sale-leaseback, the value claimed was actually paid by a tax equity investor to buy the project.

The Treasury often responds that the developer is free to claim an investment credit instead of a grant and deal with the IRS. However, it also points out that one benefit of the grant program is that any issues are worked out at inception before the grant is paid. With the IRS, it can be three years or more before issues come up on audit.

The IRS memo suggests companies receiving grants may end up running the gauntlet twice — once with the Treasury and again with the IRS.

The memo is from the IRS national office to the part of the IRS that audits tax returns.

It says three things.

If an IRS agent finds a grant was overpaid, then the recipient must report the overpayment as income in the year the grant was received. The memo gives two examples where this might occur. One is where the IRS finds that a / continued page 16

IN OTHER NEWS

does not matter if any intermediate entities, including the project company, are formed outside the United States as long as they are considered transparent for US tax purposes.

The IRS issued a similar ruling earlier this year to the owner of a solar project in Puerto Rico. (See earlier coverage in the June 2011 Project Finance NewsWire *at p. 21.) The new ruling is Private Letter Ruling is 201136018. The agency made it public in September.*

MORE SUBSTATION EQUIPMENT than many companies thought earlier qualifies for a Treasury cash grant or investment tax credit at a wind or solar project.

Most developers filing for Treasury cash grants have been treating the cost of equipment through the transformer that steps up electricity to transmission voltage as eligible for cash grants.

The IRS said in an internal memo during the summer that it will also treat circuit breakers, surge arrestors and other equipment on the high side of the step-up transformer as eligible since the equipment protects the transformer from damage. It said the devices are "power conditioning" equipment. Such equipment qualifies for tax subsidies.

The position is in Chief Counsel Advice 201122018.

Ellen Neubauer, the cash grants program manager, said that companies cannot apply for additional grants on projects on which grants have already been paid.

INSTALLED SOLAR COSTS fell 17% in 2010 to \$6.20 a watt on average for all "behind-the-meter" solar systems in the United States compared to 2009 in constant dollars, according to a September 2011 report by the Lawrence Berkeley National Laboratory.

The report said that "partial data" suggests the average cost fell another 11% in the first half of 2011 to \$5.50 a watt. Costs for systems of 10 kilowatts or smaller / continued page 17

Cash Grant Update

continued from page 15

project went into service too early to qualify for a grant. Grants were not paid on projects before 2009. The other is where the grant is passed through to a lessee, and the IRS decides the lessee claimed too high a market value. (Some projects, particularly in the solar rooftop market, are financed by leasing the project to a tax equity investor who prepays part of the rent for use of the project. The developer elects to "pass through" the grant to the lessee. Treasury rules allow the grant to be calculated in that case on the fair market value of the project.)

Some projects could lose eligibility for Treasury cash grants if transferred next year while still under construction.

Second, the memo said that the grant recipient can deduct any amount it repays the Treasury in the year the grant is repaid.

Finally, the memo said that the grant recipient can increase its basis for depreciation by half the overpayment. (If the recipient was a lessee in an inverted lease, then it has an additional deduction to the extent it reported too much income. A lessee must report half the grant as income ratably over five years.)

Congressional sources say that they thought the IRS had authority all along to audit grants. The program was originally conceived as a spending program that would be run by the US Department of Energy, but renewable energy companies pushed during debate to have it moved to the Treasury as they had more confidence in the Treasury to implement the program quickly.

The Treasury had doubts and asked Congress to clarify the IRS audit authority in a technical corrections bill in late 2009. The bill was never enacted.

The section of the economic stimulus bill that created the grant program in 2009 directed the "Secretary of the Treasury" to implement the program. The same words are used in the US tax code to mean the IRS. However, Treasury interpreted the authority to reside in the office of the fiscal assistant secretary because the grant provisions were not put in the US tax code. The Treasury view appeared to be that the IRS had no authority over the program. The same IRS branch that wrote the internal memo helped the Treasury with rules to implement the program, but it has declined to issue private rulings on grant issues as it would if investment tax credits were involved.

On one and perhaps two occasions, the Treasury has paid a grant a company requested but made it sign an agreement giving the IRS authority to audit later.

Solar Benchmarks

The US Treasury said in a posting to its website on June 30 that it expects to pay cash grants on solar photovoltaic projects of roughly $7 a watt on residential installations of less than 10 kilowatts in size, around $6 a watt on installations of 10 to 100 kilowatts, around $5 a watt on installations of 100 kilowatts to 1 megawatt, and around $4 a watt on larger projects.

These are benchmarks for solar equipment put into service during the first quarter of 2011.

Companies that claim a "materially higher" tax basis can expect more questions about their applications.

The Treasury also explained its approach for evaluating the tax bases that companies are using to calculate cash grants.

The financing structures used by many developers allow them to claim cash grants on the fair market value of projects rather than their cost.

The Treasury said it will accept three methods to arrive at fair market value, but that the cost approach, where it starts with a detailed list of costs incurred by the developer and then adds a markup or developer fee, is the "most concrete and supportable analysis and is favored by the review team." It said "appropriate markups typically fall in the range of 10 to 20 percent" with the actual amount tied to the amount of activity, capital and risk for which the developer is being compensated.

It said comparable sales data is also acceptable, but the data must be adjusted to account for any ineligible assets that were transferred as part of the project to a tax equity investor. Examples of ineligible assets include power contracts and security fences. Grants are paid only on equipment.

It said that the income approach to arrive at value is the "least reliable method" because of the large number of variables that are "subject to speculation and open to debate." It said any appraisals submitted that use the income method should be sure to allocate value between eligible and ineligible assets.

Inspector General

The Treasury released five reports in mid-October on inspector general audits of two wind companies and one solar company that received Treasury cash grants. The inspector general asked the companies to repay amounts ranging from several hundred dollars to $2.1 million.

Two of the reports involved two wind farms that E.On Climate and Renewables North America built in Texas. The projects are the 197-megawatt Inadale wind farm and the 249-megawatt Pyron wind farm.

E.On received a grant of $121.9 million on Pryon in September 2009 just eight days after applying. It received a grant of $94.2 million on Inadale in January 2010 27 days after applying.

The inspector general questioned whether the company was entitled to grants on roughly $3.5 million that the company paid for spare parts for the two projects.

Normally, grants are not paid until equipment is put into service.

Spare parts are not usually in service until they are installed. However, "emergency spares" that a company needs on hand to prevent operational downtime are considered in service even though they are not yet in use. In a sense, all spares prevent operational downtime, so there normally must be a strong back story. In this case, E.On argued that its wind farms are in remote locations making it time consuming to bring parts to the site. After conferring with the Treasury cash grant program office, the inspector general decided that E.On was right.

However, it asked for $611 back that it said was overpaid on the Inadale project. E.On had claimed a grant on a $2,038 cost item described as "Balance to Tie." The inspector general said the company was unable to provide supporting documentation.

The other three inspector general reports involve grants paid to Acciona and eSolar. / continued page 18

IN OTHER NEWS

in size ranged in 2010 from a low of $6.30 a watt in New Hampshire to $8.40 a watt in Utah. California and New Jersey, two states with the most amount of solar activity, were in the middle of this range.

Many rooftop solar systems are owned by third parties who sell electricity or lease the systems to building owners or homeowners and claim tax subsidies on the solar equipment that are then passed through to the customers in the form of a reduced electricity price or rent for use of the system. The report said that ownership by a third party added 30¢ a watt to the installed cost on average in 2010.

German homeowners paid significantly less for solar systems in 2010 than homeowners in the United States: smaller residential systems of 3 to 5 kilowatts in size cost $4.20 a watt on average, after installation, in Germany, compared to $6.90 a watt in the United States.

PERU extended a tax break in July that allows owners of wind, solar, biomass and small hydroelectric projects to depreciate the projects over five years. The tax break has been extended through 2020. At least 5% of new electricity production in Peru each year must come by law from such sources.

TAX STRATEGY PATENTS will no longer be issued by the United States under a bill that became law in September. The only exceptions are for patents on tax filing and preparation software and financial management software.

REITs can count income earned from selling carbon dioxide offset credits as good income, the IRS said.

REITs, or real estate investment trusts, are legal entities whose units are publicly traded. The capital raised is used to make real estate investments. The REIT is not taxed on its annual income, other than capital gains, as long as earnings are distributed to / continued page 19

Cash Grant Update

continued from page 17

The inspector general took issue with $117,497 in costs out of $19.5 million claimed on a five-megawatt solar thermal facility that eSolar built in Lancaster, California. The company applied for a Treasury cash grant on the project in September 2009 and was paid the grant in late February 2010. In November 2009 while the grant application was pending, it settled a claim against a contractor, which reduced the cost of the project by $80,285, but it did not update its grant application. The developer did not dispute the inspector general report, but said it has accrued other costs exceeding the adjustments since the grant application went in. If the company spent more on new capital improvements, it may qualify for an additional grant. However, the amounts must be new spending after the original application was filed. The Treasury will not pay an additional grant on costs that could have been included in the original application.

Turning to Acciona, the inspector general said Acciona should repay $2.1 million of a $67.9 million grant the company received on its EcoGrove wind farm in Illinois. The inspector general said the company should not have claimed a grant on $5.3 million in interest charges that one Acciona entity that owned the project paid another Acciona entity that supplied the turbines for a delay in paying for the turbines. The inspector general said roughly 40% of the interest claimed by Acciona supposedly accrued before the turbine supply agreement was signed. The inspector general also denied another $831,160 in costs for an "extended warranty" on the turbines. The Treasury does not allow grants to be claimed on the costs of extended warranties.

Unlike the other developers who agreed to repay the Treasury, Acciona said it does not agree with the conclusions. The Treasury cash grant team told the inspector general that it needs more time to evaluate Acciona's arguments before deciding the company should repay the money.

In the last of the five reports, also relating to Acciona, the inspector general asked for $7,277 back out of a $2.9 million grant paid on the Nevada One solar thermal project. Acciona said it was willing to adjust, but had other costs that exceeded the adjustment on which it could ask for a grant.

The inspector general staff did not appear, as of late September, to be doing any additional field work. It is unclear how many more reports might still be issued based on past visits to other grant recipients. The other visits may not have led to any adjustments.

Winds of Change In South Africa

by Clint Steyn, in Dubai

In 1960 Harold Macmillan made his famous "Winds of Change" speech that was a watershed moment in South African politics and that signaled a seismic shift in attitudes. Today, winds of change of a different sort are blowing in the energy sector in South Africa, with the sector poised to make a significant shift away from an overwhelming reliance on fossil fuels to renewable energy.

Security of electricity supply in South Africa is highly precarious. South Africa's electricity demand has substantially increased since 1994. However, no new power stations were built leading to a decline in reserve margins. In 2008, South Africa endured significant load shedding and rolling black outs. Eskom, South Africa's state-owned utility, says power supply to South Africa will remain tight, with the risk of blackouts "significantly" increasing from 2011 to 2013, and then again from 2018 to 2024.

Eskom has indicated that the country needs to add 50,000 megawatts of new generating capacity by 2028. South Africa's current generating capacity of approximately 40,000 megawatts is predominantly made up of coal, which accounts for about 90% of all domestic generation. Virtually no renewable generation exists currently.

It is a government aspiration that renewables will account for a significant proportion of new capacity.

The year 2011 looks set to be a breakthrough year for the renewable energy sector in South Africa.

On August 3, 2011, the Department of Energy launched the first-ever procurement process for renewable energy in South Africa. Under the first round of this program, South Africa will try to procure 3,725 megawatts of capacity by 2016.

The launch of the renewable procurement program followed from the issuance in March of a long-awaited integrated resource plan that featured a substantial and ambitious increase in renewable energy targets, up from 30% of new-build generation to 42%.

The run up to the launch of the renewable program was not without a few twists and turns along the way. But before we consider in detail the current state of play of the renewable procurement program in South Africa, let's go back to the beginning.

Rich Renewable Resources

As with its coal resources, South Africa is blessed with an abundance of solar and wind resources.

Wind: Africa's wind resource is best around the coasts and in the eastern highlands. It is in Mediterranean North Africa that wind power has been developed at scale, with further significant growth expected. At the end of 2009, about 96% of the continent's total wind installations of 763 megawatts were to be found in Egypt (430 megawatts), Morocco (253 megawatts) and Tunisia (54 megawatts).

Yet, despite the wealth of wind resources in Africa, under the International Energy Agency's reference scenario, only 200 megawatts of new wind capacity would be added every year until 2020. This would increase to 500 megawatts by 2030, leading to 3,000 megawatts of wind power installed in the entire African continent by 2020 and 8,000 megawatts by 2030.

In the case of South Africa, many local commentators are more optimistic, taking into account government targets and policy measures and the fact that the country is ideally suited for wind power development given its abundant wind resources, ample suitable sites and modern high-voltage electrical infrastructure.

Indeed, recent comprehensive wind mapping in South Africa has illustrated proven wind potential within the country, mostly in the coastal areas.

The South Africa Wind Energy Association estimates that with the right policy framework, wind power could provide as much as 20% of the country's energy demand by 2025, translating into 30,000 megawatts of installed wind capacity.

Solar: Every day the sun produces 100,000 billion tons of oil equivalent, while in 1998, the annual global consumption of energy was 9.8 billion tons of oil equivalent.

Both sub-Saharan and Saharan Africa have excellent solar irradiation levels suitable for efficient electricity generation, with South Africa having some of the best solar irradiation levels in Africa.

The annual 24-hour global solar radiation average is about 220 W/m2 for South Africa, compared with about 150 W/m2 for parts of the United States and about 100 W/m2 for Europe and the United Kingdom. This makes South Africa's local resource one of the highest in the world.

Specifically, the Northern Cape has excellent potential for solar power, encompassing concentrated solar power and photovoltaic technologies, with other provinces (like the Free State) also having high potential.

/ continued page 20

IN OTHER NEWS

investors. Any tax is at the investor level.

To qualify as a REIT, the entity must satisfy several tests. There are both 95% and 75% income tests. At least 95% of the REIT's income each year must be passive income and at least 75% must be passive income specifically from real estate investments. At least 75% of its assets must also be real estate, cash, cash items like receivables and government securities.

Congress gave the IRS broad authority in 2008 to treat other income as good income for both the 95% and 75% income tests "in appropriate cases consistent with the purposes of the REIT provisions."

The IRS looked at a REIT that is a general partner in a partnership that owns standing timber. The partnership signed a three-year contract with a broker who buys and resells carbon dioxide offset credits. These are credits that companies buy to offset their greenhouse gas emissions. There are both "compliance" and "voluntary" markets for such offset credits. Companies that are required by law to have offsets buy and sell credits in the compliance market.

The REIT agreed in a contract it signed with the broker not to harvest any timber on certain parcels during the three-year term of the contract, other than thinning for forest management reasons. The broker is paying the REIT the public exchange price for carbon credits times the amount of carbon the trees are assumed to absorb. If the REIT harvests timber in violation of the contract, then it can substitute another parcel. Otherwise, it must repay the broker part of what it receives for carbon offsets as a penalty.

The IRS said that the carbon offset credits are so closely linked to the use of the underlying land that the payments the REIT receives for its offset credits under the contract should be treated as good income for both the 95% and 75% income tests. The IRS explained its position in Private Letter Ruling 201123005. The agency made the ruling public in late June. The IRS told another timber REIT the same thing in Private Letter Ruling 201123003.

/ continued page 21

South Africa

continued from page 19

Ready to Take Advantage

Last year was a challenging year for the global wind industry, which saw a global decline in annual installations for the first time in almost 20 years. Structural overcapacity has led to a decline in turbine prices with Bloomberg's recently published Wind Turbine Price Index showing recently signed contracts for 2011 delivery carried a 7% discount on 2009 prices (19% discount on 2007 to 2008 prices).

Renewable energy development is picking up in South Africa with five bidding windows between November 2011 and August 2013.

Global wind power markets have been for the past several years dominated by three major markets: Europe, North America and Asia (China and India). These three markets accounted for 86% of total installed capacity at the end of 2009.

There are signs that things are changing, with emerging markets in Latin America, Asia and Africa reaching critical mass. With emerging markets like South Africa ready to start challenging these main markets in the coming years, the downward pressure on wind turbines due to market overcapacity and increased competition may result in suppliers and developers casting their eyes more intensely at these emerging markets.

It came as no surprise then that the Department of Energy received some 384 responses to a request for information for renewable energy projects issued in September 2010.

Promoting renewable energy technology in South Africa currently requires financial incentives, due to the cheaper and more reliable fossil fuel sources, but many believe that renewable energy will soon not be a more expensive option.

"The difference between the cost of new thermal generation and wind is less that you expect," says Paul Eardley Taylor, head of energy, utilities and infrastructure at Standard Bank. At the beginning of May, Eskom disclosed to Parliament that the current assumed tariff from 2015 onwards is R1.09 per kWh. The wind tariff is R1.15 per kWh, so even without carbon taxes there is not really a significant gap. Given the scale of Eskom's tariff increases, the gap between wholesale tariffs and onshore wind keeps narrowing. "Solar is also cheaper than diesel," says Eardley Taylor.

Refit Program

With an abundance of solar and wind resources, South Africa, like many emerging markets, has adopted a feed-in tariff mechanism to promote renewable energy.

The South African government published a white paper on renewable energy in 2003, which set a modest initial target for renewable energy of approximately 4% of total generation by 2013. However the renewable energy feed-in tariff or "Refit" program was only officially announced in 2009 as part of the Department of Energy's integrated resource plan.

The Refit program covered nine technologies: onshore wind, small hydro, landfill gas, biomass (solid), biogas, photovoltaic systems, concentrating photovoltaic (without storage), concentrating solar power or "CSP" trough (with or without storage) and CSP tower. South Africa is globally unusual in having three separate CSP tariffs while still not permitting lens and dish technology.

The National Energy Regulator of South Africa — called Nersa — published its Refit tariffs in 2009 for these technologies, including a tariff of R1.25 per kWh for wind and R3.94 per kWh for solar PV.

The Refit program was given a substantial boost by the issuance in March and promulgation in May 2011 of the long-awaited integrated resource plan called "IRP 2010." The IRP 2010 outlines the proposed power generation mix for South Africa for the period 2010 to 2030.

The most striking feature of the final, so-called "policy adjusted" IRP 2010 was the increase in the overall contribution of renewable energy to the generation mix, up from 11,400 megawatts in the draft plan to 17,800 megawatts, some 42% of targeted new generation. The IRP 2010 included a defined technology split of the renewables allocation, with wind and PV each contributing 8,400 megawatts and CSP contributing 1,000 megawatts. Nuclear is expected to contribute 23% and coal 15%.

Many commentators remarked that solar PV emerged as the big winner from this process with the target of 8,400 megawatts translating into the deployment of a "staggering" 300 megawatts of large-scale solar PV per year from 2012 onwards.

By 2030, coal is still likely though to represent some 50% of the total mix at around 41,000 megawatts. Under the plan, a total of approximately 56,000 megawatts of new capacity will be added over the next 20 years, raising the country's total capacity to some 89,000 megawatts by 2030. Of the new capacity, there is a total of about 42,000 megawatts that is yet to be committed, with the balance already being built by Eskom.

Under the IRP 2010, the first phase of 1,025 megawatts of renewable projects was intended to be completed by the end of 2013. The IRP 2010 also includes time frames for the phased development of projects over 20 years, with specific megawatt allocations in different years. It required 300 megawatts of solar PV per year from 2012 to 2024, further increased to 500 to 1000 megawatts per year until 2030, and 200 megawatts of solar CSP by 2015, with 100 megawatts per year through to 2025.

Uncertainty as Nersa Intervened

Following issuance of the IRP 2010, it had been anticipated that the procurement process for the first round of a relatively modest 1,025 megawatts of renewables projects would be quickly launched by the publication of the Refit request for proposals.

However, days after it was confirmed that the role of renewable energy in South Africa's generation mix would be substantially increased, Nersa issued a consultation paper proposing a material decrease in the Refit tariffs when compared to the previously agreed and promulgated 2009 tariffs, rather than commence with the procurement process.

The proposed reductions ranged from 7% on some technologies to 41% on others, including a 25% reduction in the tariff for wind from R1.25 per kWh to around R0.94 per kWh.

In its consultation paper at the time, Nersa said that the tariffs had been reduced based on 2011 market conditions, reflecting a reduction in the nominal / continued page 22

IN OTHER NEWS

The conclusions only hold for REITs that are not in the business of selling carbon offset credits. In the second ruling, the IRS said carbon credits are not inventory held for sale to customers. That ruling involved a US REIT that was selling carbon offset credits that it received from a foreign government for maintaining forests in a foreign country.

ANAEROBIC DIGESTER owners have been claiming refundable federal tax credits of 50¢ a gallon on methane made from hog and cattle manure and crop residue. The methane is used to generate electricity.

The IRS national office said in an internal memo that the agency made public in late August that the tax credits are not allowed. The memo is Chief Counsel Advice 201133010.

A tax credit of 50¢ can be claimed on each gallon of "alternative fuel mixture" that a company produces, provided the mixture is then sold to someone else for use as fuel or used directly as fuel by the company doing the mixing.

Manure and crop residue qualify as alternative fuels. Some companies mix a small amount of diesel fuel in with the manure or crop residue before it is fed through the biodigester and claim they have made an alternative fuel mixture. Others use atomizers to spray diesel fuel in the methane produced by the biodigester as the methane moves toward the generator where it is converted into electricity or else they add diesel fuel directly to the generator simultaneously with the methane.

The IRS said that in the first case where the diesel fuel is mixed with manure or crop residue before it is fed into the biodigester, the mixture is not being used a fuel. It said that in the second case where diesel fuel is sprayed into the fuel stream feeding the generator, no single alternative fuel mixture is produced. Two separate fuels —methane and diesel fuel — are consumed at the same time in the generator.

/ continued page 23

South Africa

continued from page 21

cost of debt and inflation, and a strengthened Rand-to-US-dollar exchange rate, since the 2009 tariffs were set.

A senior Department of Energy official confirmed in mid-June that the government intended to pursue a competitive bidding process for South Africa's first wave of renewable energy projects under the Refit program.

Ompi Aphane, the deputy director-general for electricity, nuclear and clean energy, said, "We're definitely going to have price competition on the different technologies." His comments raised questions about the future of the Refit tariffs adopted by Nersa two years ago.

There seemed to be some misalignment between the processes of Nersa and the government, with the government proposing that Refit prices, instead of applying across the board according to levels determined by Nersa, will serve as an upper guide in a competitive bidding process.

Aphane said the Refit rates would act as a "ceiling" beyond which bids would not be considered. To meet other objectives, such as localization, bidders would first be required to pass a set of minimum requirements. "Those that make the thresholds then go into the next comparison, which is price."

Reactions

Though there had been discussions in the sector about the possibility of a revision in Refit tariffs, particularly in light of improvements in technology pricing and as a result of a change in exchange rate assumptions used, Nersa's announcement came as a shock to the industry, in light of its timing a week or so before the procurement process was widely expected to commence.

Nersa's move appeared to surprise even the Department of Energy, which initially said that the higher tariffs should apply for the first round of Refit bids to go out to tender because their projects had to be ready by 2013 and would therefore cost more.

The proposed tariff changes and the mooted adoption of a competitive bidding model raised alarm in the sector, while the magnitude of tariff drops worried some technology segments.

South Africa Wind Energy Association board member Ian Macdonald has said that recent developments were "disappointing," particularly owing to the fact that, until April, the one constant in the much delayed renewables process had been the tariff. The 2009 Refit stimulated material investor interest. It is estimated that wind energy developers had already risked over ZAR 400 million developing projects to participate in the Refit program on the premise of the tariffs promulgated in 2009.

Many in the renewables sector have argued that the Refit model, which offers a guaranteed purchase price, had emerged as "best practice" globally for supporting the development of the fledgling renewables sector.

More than 60 countries had pursued the model and developers argued that it has delivered better results when compared with those countries that opted for competitive bidding. The key danger, they argued, is that inexperienced and overly-optimistic developers bid low in order to secure the tender, but are then unable to raise the project finance required to construct projects.

The wind trade association pointed to a detailed 2008 analysis by the European Commission that concluded that "well-adapted feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity."

In contrast to most of the renewables developers, there were some developers, particularly in the solar sector, who supported the tariff reductions, with Olivier d'Huart of PV manufacturer Amonix saying that the revised solar tariffs were internationally competitive and that the 2009 tariffs were "over generous."

Renewables Program Launched

The long-awaited procurement process for South Africa's first renewable energy projects commenced on August 3, 2011 with the publication of the South African renewable energy IPP request for proposals.

The request for proposals seeks to procure 3,725 megawatts of renewable generation by 2016 in the first round of procurement. This is a significant increase from the 1,025 megawatts of capacity that market commentators had been expecting.

There is a defined allocation between various renewable technologies, and the request for proposals sets a tariff cap for each technology. A bid will be considered non-compliant and be automatically rejected if the price cap is exceeded. The table below summarizes this allocation as well as the relevant tariff caps.

Technology	Allocation (megawatts)	Tariff cap (R/kWh)
Wind	1,850	1.15
Solar PV	1,450	2.85
CSP	200	2.85
Biomass	12.5	1.07
Biogas	12.5	0.8
Landfill gas	25	0.6
Small hydro (less than 10 MWs)	75	1.03
Small projects (1-5 MWs)	100	As above

A key feature is the significant increase in allocation of capacity to solar PV.

The evaluation criteria in the request for proposals contemplate a two-step tender process. Projects will first compete on a number of "qualification" criteria and gatekeeper issues such as status of land rights, environmental permitting and various technological and financing criteria.

Those projects that get through the first round will then move to round two where they will compete against each other on certain stipulated evaluation criteria. The two main criteria are price and economic development.

Each technology has its own economic development matrix, but common to all are questions of job creation, local content (with special emphasis on local manufacturing), rural community development, skills development and education, enterprise development, socio-economic development and participation by the historically disadvantaged. The points allocation between price and economic development is 70/30.

There are five bidding "windows" — November 4, 2011, March 5, 2012, August 20, 2012, March 4, 2013 and August 13, 2013. If the maximum allocable megawatts for any particular technology have been allocated during any particular window, then the subsequent windows will not be opened for that technology.

The request for proposals includes a drafts of a power purchase agreement, implementation agreement, direct agreement and connection agreement. Unusually these agreements are non-negotiable and no bidder mark ups will be allowed.

Bidders whose responses rank the highest will be appointed preferred bidders, with as many being appointed as may be necessary in order to provide the maximum allocation of megawatts for each technology. These / continued page 24

IN OTHER NEWS

The alternative fuel mixture credit is a credit against federal excise taxes collected on gasoline, diesel and other fuels at the pump. However, the credit is refundable in cash or can be converted into an income tax credit if the taxpayer does not pay enough in excise taxes to absorb the full credit. The alternative fuel mixture credit is found in section 6426(e)(1) of the US tax code. It will expire at the end of December unless extended by Congress.

A DISTRICT COOLING SYSTEM, including underground pipes, can be depreciated over seven years, the IRS said.

A power company bought another company that owns a district cooling system in a large city. The system includes three plants for chilling water, a closed-loop system of underground pipes that run the water underneath a baseball stadium and downtown buildings and then back to the chillers to be re-chilled, and heat exchangers at each customer's location to pull the cold temperature out of the water.

Equipment used to supply steam or water to customers must be depreciated over 20 years. Assets belonging to pipeline companies that transport gas, oil or other products to customers by pipeline are depreciated over 15 years. The IRS said the district cooling company is not in either business because it is not delivering steam or water to customers; the water is retained for use in the chillers.

The IRS also considered whether the underground pipes are part of the buildings to which they are connected. Buildings and similar "structural improvements" are depreciated over 39 years. However, it decided the pipes are equipment rather than buildings, even though the US Tax Court said in 1981 that a district cooling system that served a single apartment building was a structural component of the building. The Tax Court said the fact that the apartment building and the / continued page 25

South Africa

continued from page 23

bidders would then need to conclude a power purchase agreement with Eskom, finalize connection agreements and sign an implementation agreement with the Department of Energy. Projects bidding in the first window are expected to reach financial close by June next year.

Eskom has been specifically excluded from bidding any of its renewables projects, and the state-owned utility's role has been confined to that of buyer and to connecting the projects to its grid.

Market Response

Market reaction has generally been positive. "We're impressed with the request for proposals," said Standard Bank's Eardley-Taylor. "Although it has been along time coming, it is a solid eight out of 10."

Potential developers have indicated that the tariff caps did not appear to be unrealistic, but some were concerned about the number of requirements being added that were unrelated to the core business of power generation.

The Department of Energy has confirmed that more than 400 companies paid the R15,000 application fee to receive the bid documents, although about 270 of those could be considered to be potential IPP developers with the balance being made up of potential financiers and equipment suppliers.

The government is understood to be very pleased with the response, particularly against the backdrop of the initial disquiet expressed by potential developers when it was confirmed that the renewable energy feed-in tariffs had been abandoned in favor of a competitive bidding process.

Director General Nelisiwe Magubane said the response had been "better than expected" and that further applications were likely from foreign and domestic companies. She added that the response also bodes well for delivery on the objective of building a "sustainable" renewables industry, which could lead to development of some 18,000 megawatts of renewable energy by 2030.

It has taken a while and there have been twists and turns along the way, but the renewables program in South Africa is up and running.

With the first round of the procurement process expected to generate between $10 billion and $12 billion in foreign and domestic investment in the renewables sector in South Africa, it appears the winds of change in the energy sector in South Africa are more than just hot air. ◎

Financing Rooftop Solar Projects in the US

The larger US solar rooftop companies have used various forms of master tax equity facilities to finance their projects. A panel of tax equity investors talked about the market at an Infocast distributed solar conference in New York in June. The panelists are Jeetu Balchandani, head of the global structured tax products group at MetLife Capital, Jason Cavaliere, director of renewable energy finance with Citigroup, Darren Van't Hof, director of renewable energy investments with US Bank, and Mit Buchanan, a managing director of JP Morgan Capital Corporation. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Jeetu Balchandani, Metlife Capital is interested in investing tax equity in the rooftop market, but just commercial projects or also residential?

MR. BALCHANDANI: Primarily rooftop commercial. We have done a couple programs of approximately $50 million each where we have multiple commercial rooftop sites. The challenges in getting such deals done are to be able to evaluate each credit, to keep the transaction costs on a manageable scale and to limit the number of separate fundings. Residential solar is still challenging for us. We have not gotten our arms around that yet.

MR. MARTIN: How frequently are you prepared to fund under such facilities?

MR. BALCHANDANI: Ideally once a quarter. However, we are not terribly stringent about that and try to accommodate the sponsor whenever we can. For the two programs we have done to date, we have had four to six fundings in each program over the course of a year.

MR. MARTIN: Jason Cavaliere, I know Citigroup has done at least one large residential portfolio. Are you also interested in commercial rooftop transactions?

MR. CAVALIERE: We did our first transaction in the residential space. We find that more attractive than the commercial space in a number of ways. One is that with a large enough pool of residential customers, you can take a statistical approach to the credit analysis. Commercial projects require looking at each individual credit.

MR. MARTIN: Is a residential pool lower risk?

MR. CAVALIERE: Not lower credit risk but easier to estimate the credit risk.

MR. MARTIN: So then the cost of capital would be lower for a residential deal than a commercial one?

MR. CAVALIERE: Exactly. [Laughter] I know it's fun to beat up the banks on this, but our regulators are becoming more strict. We may have enough capital, but the hurdle rates that we need to pass to deploy that capital are extremely high. Most banks are adhering currently to Basel II before Basel III takes effect. Basel II does not allow banks to assign retail treatment to the transaction until there are at least five years of historical data. We don't have five years of recent data yet in this sector, and this lack of data leads to a very onerous capital charge.

MR. MARTIN: Darren Van't Hof, you have been doing both commercial and residential rooftop. You were one of the early movers. How risky have these deals been, and how many years of data do you have? What has the default rate been for residential customers?

MR. VAN'T HOF: We have about $500 million in residential portfolios under management. The default rate across nearly 20,000 customers has been less than half a percent over three years.

We try to limit participation to customers who qualify for prime mortgages. They own their homes. They are pretty high income earners. They have pretty low debt ratios. All of those things lead to strong portfolios.

MR. MARTIN: Do you have any sense how common defaults are among commercial customers?

MR. VAN'T HOF: We have had no defaults on any of our commercial systems.

MR. MARTIN: What minimum FICO score do you require for homeowners to allow them into the pool?

MR. VAN'T HOF: It is usually around 700. In cases where we have gone lower, we have tried to reduce the risk by requiring the customer to prepay all or part of the rent or electricity payments.

Minimum Deal Size

MR. MARTIN: Mit Buchanan, JPMorgan is a dominant player in the US tax equity market. How interested are you in residential and commercial rooftop projects? Your bio you said you have done one portfolio so far.

MS. BUCHANAN: We are interested on the commercial side. We closed a portfolio that required a $60 million gross investment on our part. We are looking at residential, but have not closed a residential deal to date. What / continued page 26

IN OTHER NEWS

cooling system were owned by different taxpayers did not prevent it from being a structural improvement. The IRS said this case is different because the cooling system serves multiple customers and none of the customers has a right to take ownership of the pipes after a default.

The ruling is Private Letter Ruling 201131010. The IRS made it public in August.

A DEPRECIATION BONUS was allowed on a new hydrogen pipeline, even though the hydrogen company effectively committed to build the pipeline before the depreciation bonus became available in 2008.

The hydrogen company wanted to claim a 50% depreciation bonus, meaning deduct half the pipeline cost immediately and depreciate the remaining cost over 15 years. A depreciation bonus cannot be claimed if the company signed a binding contact to "acquire" the pipeline before 2008. The IRS said the fact that the company had a contract in 2007 to supply hydrogen to a customer and the contract required it to construct and own a pipeline to deliver the hydrogen to the customer did not mean the hydrogen company committed to "acquire" the pipeline in 2007. For one thing, the company did not "acquire" the pipeline; it built a new pipeline. The IRS also said the contract provision that made the hydrogen supplier responsible for the pipeline merely addressed how costs would be allocated between the hydrogen company and the customer.

The ruling is Private Letter Ruling 201140002. The IRS made it public in mid-October.

BIOFUEL producers may soon have access to additional financing from the US government of up to $510 million over the next three years for construction of new, or retrofitting of existing, plants to produce "drop-in" biofuel.

"Drop-in" biofuel is biofuel that can be mixed with petroleum-based fuel without any problems. The Department of Energy has committed to seek / continued page 27

Rooftop Solar

continued from page 25

we are looking for in both segments is the opportunity for repeat business because you want to get papers in place and then hopefully replicate them but for the due diligence.

MR. MARTIN: How large a portfolio do you need before a deal is of interest?

MS. BUCHANAN: I would say $50 to $60 million in terms of a gross tax equity investment. Depending on the cost per megawatt, that usually means a portfolio of at least 10 to 12 megawatts. That is still very small for us, but we are committed to solar.

MR. MARTIN: Darren Van't Hof, how large does the deal have to be before you are interested?

MR. VAN'T HOF: That is the right size for a solar rooftop portfolio. They take a long time and they're really messy. You will start with five or six assets and, by the time you close, two or three of the customers might have been swapped for other customers. That doesn't seem like a big deal from a developer's perspective, but on the bank side it can soak up a lot of time. If you have a lender providing project-level debt at the same time and it is not your own institution, the transactions can get very expensive very quickly. The size is driven less by our need to get capital out the door than by the inefficiencies that we would impose on the developer for anything smaller.

MR. MARTIN: You said if you have another lender. Do you mean another tax equity investor or actually a lender?

MR. VAN'T HOF: A lender.

MR. MARTIN: So you are combining tax equity with debt in rooftop transactions.

MR. VAN'T HOF: Yes.

MR. MARTIN: You would think that the transaction costs would be too high.

MR. VAN'T HOF: They are. [Laughter]

MR. MARTIN: Jason Cavaliere, how large does the deal have to be?

MR. CAVALIERE: For us, $25 million net equity would be the minimum for a residential portfolio.

MR. BALCHANDANI: I think we're pretty much in the $50 million range. These things do take a lot of work, and you do have projects that fall out, so you might start at $50 million and end up at $30 or $40 million.

MR. MARTIN: In terms of the economics of the deals and the cost of money, is there a difference between distributed solar projects on the east and west coasts?

MR. CAVALIERE: In New Jersey, as much as 80% of your gross revenues come from the sale of SRECs. SREC prices collapsed and while people talked about sponsors having the ability to bridge that SREC risk, financial institutions can't. We can bank contracted RECs only. There are many deals in New Jersey on which we have had to pass.

MR. VAN'T HOF: The other challenge in a high SREC market is who the offtakers are. Many buyers of SRECs are brokers. From a financial institution perspective, that doesn't cut it. Investment grade utilities need to be on the other side of those contracts.

MS. BUCHANAN: I agree with that. The economics are very thin in these deals on either coast, but the extra risk on the east coast is the share of revenue that comes from selling SRECs. We have to have a long-term contract with an investment grade counterparty to be able to count the cash flow.

MR. MARTIN: So there is no point in a developer going to some small shop that acts as a go-between, buys SRECs and resells them into the market. Electricity prices are highest in New England, including New Jersey, and then California. One would think that in terms of electricity prices the deals are fairly similar on both coasts?

MR. VAN'T HOF: The incentive structure is different. The PBI rebate program in California was very successful and a lot more bankable. Otherwise, you are right. There is an inflection point where the electricity prices start to get so high that the economics are easier. However, we see a lot of power contracts that are underbid to win market share, and that becomes more of a challenge.

MR. MARTIN: Does it matter if SREC prices collapse in New Jersey and Pennsylvania as far as tax equity investors are concerned? Mit?

MS. BUCHANAN: I think given our criteria of where SRECs need to be sold under a contract with an investment grade offtaker, it doesn't matter. We will not take SRECs into account unless that criterion is met.

Deal Structures

MR. MARTIN: There are three main structures in the distributed solar market. Master sale-leasebacks, master partnership flips and master inverted leases. Does MetLife have a preference for one of the structures?

MR. BALCHANDANI: We have done master sale-leasebacks and are comfortable with that structure. There is no leverage involved. We can keep transaction costs to a minimum. Given the complexities of doing distributed generation in any case, this is the simplest possible structure. So we will probably only do such transactions.

MR. MARTIN: Is the cost of capital for the developer higher in a single investor lease than a leveraged lease?

MR. BALCHANDANI: Possibly. Frankly, we have not done the analysis of transaction costs and how that really layers into it. Also, the complexity of getting a lender involved is too much. It is one thing to get one party comfortable with each customer credit. If you have to get a lender comfortable as well, you're really taking the highest common denominator. The point is there are trade offs for a developer to consider in the effort to pick up a hundred basis points.

MR. MARTIN: How long will you leave the master lease facility open — for a year, two years — so that more equipment can be added to it?

MR. BALCHANDANI: We have been fairly flexible, but I think a year is about as far as we will go.

MR. MARTIN: And you will commit to a certain cost of money for that year?

MR. BALCHANDANI: For that period, right.

MR. MARTIN: Citigroup has been doing mainly inverted leases. Can you explain what an inverted lease is?

MR. CAVALIERE: An inverted lease is where the tax equity investor, which is usually the lessor in a sale-leaseback, is the lessee and the developer remains the lessor, keeps the depreciation, but assigns the Treasury cash grant or the investment tax credit to the lessee, and the lessee, being Citi, faces the customers directly.

MR. MARTIN: What's the attraction of that structure to a developer?

MR. CAVALIERE: It is extremely attractive to developers. We prepay some of the rent, so the developer has cash up front. Basically the residual goes back to the developer for free. The developer does not have to pay anything to get the assets back. In the structure, Citi, as lessee, is taking the credit risk of the residential customers, whereas in a partnership flip or sale-leaseback, customer credit risk remains with the developer.

MR. MARTIN: How long a term does a typical inverted lease have?

MR. CAVALIERE: We want the inverted lease to remain in place significantly beyond the terms of the customer contracts. However, there may be some type of walk-away right or purchase option before the end of term. / continued page 28

IN OTHER NEWS

$170 million in new appropriations while the Department of Agriculture and the Navy will each "repurpose" $170 million of already appropriated funds.

An executive steering group made up of representatives from all three departments is still working out the details of the program. Either the Department of Energy or the Navy is expected to contract directly with developers of biofuel plants pursuant to the Defense Production Act. This legislation, enacted at the start of the Korean War, gives the president broad authority to contract and spend funds for national defense. It has been used by the US military in the last two decades to promote innovative military technologies. The Navy is expected to be the offtaker of the biofuel produced. However, it is not clear whether the Navy will be able to commit to an offtake arrangement whose term exceeds five years.

The Department of Agriculture's commitment to "repurpose" $170 million in already-appropriated funds for the program is being made under the Commodity Credit Corporation Charter Act that authorizes the government to stabilize farm prices and income. This suggests its role may not be directly funding the construction of biofuel plants but rather providing price stability of the feedstock for biofuel production.

MINOR MEMOS. There is a chance that any jobs bill on which Congress is able to agree this year will extend a 100% "depreciation bonus" through December 2012. The bonus is the ability to deduct the entire cost of new equipment in the year the equipment is put in service. (For renewable energy projects that benefit from Treasury cash grants or investment credits, 85% of the cost could be deducted.) There would be no other depreciation. President Obama called on Congress in September to extend the 100% bonus. Obama is a Democrat. Eric Cantor, the majority leader in the House, which is Republican controlled, identified the bonus as an area of "potential common / continued page 29

Rooftop Solar

continued from page 27

MR. MARTIN: So how long is the term? 12 years? 15 years?

MR. CAVALIERE: The inverted lease term is usually 20 to 25 years with a right to walk away or a purchase option around year 10.

Percentage of Capital Raised

MR. MARTIN: Jeetu Balchandani, what share of the capital cost of the systems does the sale-leaseback structure raise for the developer?

The default rate in residential solar deals involving a total of 20,000 customers has been less than 0.5% over three years.

MR. BALCHANDANI: As much as 100%.

MR. MARTIN: As much as 100%, but developers in the current market are usually required to prepay part of the rent, so what do you end up with on a net basis?

MR. BALCHANDANI: It depends because the developer's actual cost to construct the systems may be less than the fair market value paid by the lessor in the sale-leaseback. So in certain cases the developer is getting 100% of the construction costs and maybe even making a profit, even after taking the rent prepayment into account.

MR. MARTIN: So the developer is making a profit on the sale part of the transaction before he leases back the solar equipment and sometimes you require all or part of that profit to be paid to you as prepaid rent.

Jason Cavaliere, how much of the capital cost can a developer raise through an inverted lease?

MR. CAVALIERE: It depends on the lease term, the lease rates or electricity prices for which the customer is being charged, and whether there are any local rebates. We can get close to $5 a watt payment which is close to 100% depending on the location. However, it would be safer to assume the developer is raising somewhere in the mid-$4-a-watt range as an upfront payment of rent under the inverted lease.

MR. MARTIN: That is a very significant share of capital costs when the only tax benefit for the lessee is a 30% Treasury cash grant on the equipment. Are you keeping a large share of the customer payments over time to get to such a high percentage?

MR. CAVALIERE: We prepay 100% of the rent for an initial period under the inverted lease, and we keep all the customer revenues during that period. We can structure it where we pay the developer rent over time; however, developers usually want all of the money up front.

MR. MARTIN: So you take the customer credit risk.

Darren Van't Hof, you have pioneered various structures. The latest one is a partnership flip in which the flip occurs at the end of year five regardless of your return. Are you using that structure in the distributed solar market or is it just for wind?

MR. VAN'T HOF: No, we use it in the distributed solar market, and it is a clean, quick structure. It works for sponsors that can provide a fair amount of equity capital. It does not raise as much tax equity as other structures. We do not take as much cash as Citibank takes in an inverted lease, but we are not providing nearly as much tax equity. The benefit is that we will exit the transaction in five years, and the developer will own the equipment. The developer can refinance it, recapitalize with other equity and get us out of the way. Developers like that.

MR. MARTIN: My understanding of the structure, having worked opposite you on two of these deals, is that you take 2% of the cash before and after the flip.

MR. VAN'T HOF: It is actually 2% indexed to our equity. Sometimes it can be as high as 7% to 10% of gross cash flow.

MR. MARTIN: The main attraction to the developer is he sheds the tax benefits while keeping most of the cash.

MR. VAN'T HOF: That is correct. Actually, the structure also works well with traditional project finance debt at the project company level once we get through the inter-creditor terms.

MR. MARTIN: What percentage of the capital cost of a rooftop solar system can be raised with a fixed-flip structure?

MR. VAN'T HOF: About 40%.

MR. MARTIN: Mit Buchanan, you have done sale-leasebacks and traditional partnership flip transactions. What is JPMorgan's preferred structure for the distributed solar market?

MS. BUCHANAN: We are agnostic. We will look at both partnerships and single investor leases, but I think distributed generation works very well as a single investor lease. We are trying to get $50 to $60 million out the door per transaction. It is hard to do with such small systems without multiple closings. A single investor lease provides more flexibility to close around groups of systems because the parties have up to three months after each tranche of equipment is put in service to close. In addition, there is typically a prepayment of rent by the developer . The structure is based on the fair market value of the equipment after installation. The developer typically prepays 15% to 20% of the rent, so it ends up having raised about 80% of the fair market value of the equipment.

MR. MARTIN: How large a rent reserve do you require the developer to maintain?

MS. BUCHANAN: We ask for a reserve that holds enough money to fund O&M costs and rent for six to nine months. That and the need to prepay some of the rent are why the developer raises about 80% of the market value of the systems on an all-in basis.

MR. MARTIN: Are the reserves cash or will you accept a letter of credit?

MS. BUCHANAN: We will accept a letter of credit as long as we are comfortable with the letter of credit bank.

MR. MARTIN: Are you also doing partnership flip structures in this market?

MS. BUCHANAN: We will. We have a bid outstanding that contemplates using a partnership, so I expect to close on that basis. However, we are seeing more partnerships in utility-scale solar projects than in the rooftop market.

MR. MARTIN: How do you persuade developers that your product is better for them than Jason Cavaliere's inverted lease or Darren Van't Hof's fixed-flip partnership?

MS. BUCHANAN: It is not necessarily better; ours may be better suited depending on a developer's objectives. I encourage every developer to calculate its NPV benefit from each form of available financing. Look at every option. To me, the single investor lease has a benefit of providing financing on the fair market value of the equipment after installation. The developer is also getting most of its profit out at inception. The cost per watt must be reasonable, and there must be an acceptable appraisal that supports the profit.

/ *continued page 30*

IN OTHER NEWS

agreement" . . . . Europe is considering a financial transactions tax of 0.1% on shares and bonds and 0.01% on derivatives. The European Commission released a formal proposal on September 28. The proposal must be approved by all 27 European Union members to be imposed. Britain is expected to veto the proposal unless it can opt out. One option under discussion is to impose the tax only in the parts of Europe that use the euro. All financial institutions that are tax residents of countries imposing the tax would have to pay it on transactions in which they are involved, even if the transaction is carried out abroad. Sweden experimented with a financial transactions tax from 1984 to 1991. The tax was reported to have led to an 85% drop in transaction volumes . . . . The parent company of Virgin Airways is moving its trademarks and other brands to Switzerland in a move that is expected to reduce UK taxes for the group . . . . The IRS analyzed in an interesting internal memo made public in August whether a power company could calculate its income from a contract to supply electricity to an aluminum smelter by marking the contract to its market value at the end of each year and reporting the gain or loss as its income. A "dealer in commodities" can use that approach to calculate its income. Electricity is a commodity for this purpose. However, in the particular case, which was under audit, the IRS said what looked in form like a contract to sell electricity was really a tolling agreement. The smelter supplied the fuel the power company used. Therefore, mark-to-market accounting could not be used for it. The IRS also said the decision whether to use mark-to-market accounting can be made by each legal entity separately even in cases where all the entities join in filing a consolidated federal income tax return. The memo is Chief Counsel Advice 201132021.

— *contributed by Keith Martin, John Marciano, Amanda Forsythe and Samuel Kwon in Washington and Adam Gale in New York.*

Rooftop Solar

continued from page 29

Section 1603 Payments

MR. MARTIN: The developer gets his profit as gain on the sale part of the sale-leaseback transaction.

All of you have been doing Treasury cash grant deals. What has been your experience with Treasury cash grants? Is Treasury paying the full grant for which you apply?

MR. VAN'T HOF: You are looking at me? [Laughter]

MR. MARTIN: Yes, I am. I know you made a trip to Washington at one point. I assume it wasn't just a sightseeing visit.

MR. VAN'T HOF: We did. We had an interesting and helpful meeting in the basement of the Treasury building. There were a number of kinks to work out in the program as it applied to residential solar systems. The Treasury was not prepared at the start to deal with literally thousands of applications on individual rooftop installations. Residential systems cost more per watt on an installed basis than what the government was used to seeing at larger solar projects, and the people reviewing the grant applications at National Renewable Energy Laboratory, under contract to the Treasury, looked at the cost of silicon and said the bases that applicants were using to calculate their grants were too high. They did not take into account the development activity around each residential system. Since that initial period, the program has been great. It has been a very successful program in terms of encouraging capital to flow into the residential rooftop market, and we give the people running it at Treasury and NREL high marks.

MR. MARTIN: How quickly are you being paid grants after filing applications?

MR. VAN'T HOF: We receive some in as quickly as three weeks and others in as long as six months.

MR. MARTIN: What about others' experiences? And on what bases are you being paid grants on rooftop solar systems? Is it $7 a watt, $6 a watt, $8, what?

MS. BUCHANAN: I think the bases are trending down. Six to nine months ago, the bogie seemed to be $7 per watt for a typical rooftop deal. The individual facts are important. For example, Treasury understands that installation costs are higher in certain markets. It can be a process sometimes of trying to socialize the cost per watt to see whether you can get any feedback from Treasury before filing the grant application. [Ed. Shortly after the panel discussion, the Treasury posted a paper to its website to let the rooftop solar market know what it considers reasonable values for rooftop installations. The amounts vary from $4 a watt for systems of greater than 1 megawatt in size to $7 a watt for small residential systems. These figures were for systems installed in the first quarter of 2011.] We have seen grants paid in the amounts we requested and, at other times, there have been haircuts. As panel prices come down over time, the grant bases also come down. Our experience is the reviewers at NREL dig into the facts. If the amount requested falls within a range that NREL considers reasonable, the grant gets paid. If not, there is a greater risk of a haircut.

MR. CAVALIERE: We are in the mid-$7-a-watt range, and we just received a grant confirmation last night without any reduction.

MR. BALCHANDANI: We have seen some haircuts around the $7-a-watt level. For the projects that get pushback, sometimes it is possible to explain why the project costs more than the typical project. Sometimes the explanation is the panels were purchased at a time when panel prices were higher.

MR. MARTIN: Have you found Treasury receptive to these types of arguments?

MR. BALCHANDANI: They listen. They may or may not accept the explanation.

Cost of Tax Equity

MR. MARTIN: At the annual Chadbourne energy conference this summer, Ted Brandt, who's CEO of Marathon Capital, said the cost of tax equity seems to be more a function of supply and demand than any realistic assessment of risk in these deals. He was looking at the fact that interest rates on debt have been falling but tax equity is still 270 basis points more expensive than it was before Lehman went bankrupt. Is he right? And shouldn't large residential portfolios be the least risky asset classes, even less risky than wind given the diversification you mentioned earlier?

MR. CAVALIERE: I don't think Ted is right. Ted doesn't have the same regulators we have. I don't think he has any. [Laughter]

The yields we charge on deals just meet the minimum return the bank regulators require us to earn on the type of capital we are deploying. We are not trying to sack the market.

MR. BALCHANDANI: I think to a large extent it is supply and demand. At the end of the day, we are a provider of capital, and we have a fiduciary duty to our shareholders to get the best return for the dollars we invest. If we can earn a higher return by deploying the capital elsewhere, it will go into those other investments.

MR. MARTIN: Many people think that yields in the tax equity market will increase as the Treasury cash grant disappears. Tax subsidies amount to about 56% of the capital cost of wind and solar projects. At the moment, 30% is being paid in cash. Once the market has to use that 30% against tax capacity, the market will need to find as much as twice the tax capacity as this year to handle the same volume of projects. Are we headed for much higher rates given this problem?

MR. VAN'T HOF: There could be a premium. You are asking a financial institution to put its balance sheet behind your project, and there is a bit of a premium to that. It is a function of supply and demand. We are winning deals at X% yield, and we go to our credit people and they ask whether we would still have won the deals at X+%. If the answer keeps coming back yes, there is no reason to reduce our yield. We have a fiduciary obligation to our shareholders.

There are three main financing structures in the distributed solar market. Each raises a different amount of capital.

MS. BUCHANAN: I agree. There is already a premium if you ask us to take an investment tax credit rather than a Treasury cash grant because we are using up more tax capacity, which is a scarce commodity. There are also alternative uses of capital, so you want to make sure that what you bring to your credit committee is a well-priced good investment for the corporation to make. Another factor is the number of tax equity investor competing against each other in the market. There are perhaps 18 or 19 currently with another four or five on the edge of entering the market. Once you take away the Treasury cash grant, rather than 19+, maybe you have 10.

MR. CAVALIERE: Let's also remember the lesson we all learned a couple of years ago that there is volatility of tax capacity in each institution. The opportunity cost of using that capacity is going up.

MR. MARTIN: Tax equity for the least risky wind farms costs between 8% and 8.25% currently. Solar PV used to be priced at roughly the same level as wind. In the last year, it has been all over the map. Unleveraged tax equity for solar PV has been in the high single digits to the low teens on an after-tax basis. What is your sense where it is today? Talk about commercial versus residential.

MR. VAN'T HOF: I think it is in the mid-teens, honestly.

For instance, we don't do sale-leasebacks, although we hope to be in that market by the end of the year. There is a big difference between getting an 8% yield over five years versus 15 years. It is an acceptable yield over five years but not for putting money at risk over a much longer period.

MS. BUCHANAN: It is hard to make a definitive statement about yields. Many factors are at work in particular markets. For example, you want to make sure you are getting comparable returns with other investments with equivalent levels of perceived risk. Ground mounted systems may be different than rooftop. The customers may be different. Sometimes the yield may be lower because there is the potential for significant repeat business if you can land the first deal.

MR. MARTIN: Which is riskier — wind or solar PV?

MS. BUCHANAN: In some ways solar should be less risky because you have fewer moving parts. You don't have the intermittency. But, having said that, if you do a lease deal and you have a power contract with a term of 20 years and a site lease with a term of only 20 years, and the tenant is a retailer who might last only seven years, those sorts of things have to be factored in.

MR. MARTIN: So your tenant could be a video store.

MS. BUCHANAN: [Laughter] That would not be in our portfolio.

MR. CAVALIERE: Somebody did come to us with a paintball facility and I said, "I can't take this to the credit committee." [Laughter] Having an investment grade offtaker is a good starting point.

MS. BUCHANAN: I would start with a return comparable to wind, but then adjust for the fact that you are talking about potentially a 20-year investment through a single-investor lease versus seven to 10 years for the wind farm.

MR. MARTIN: Mit, you said that a developer should compare the NPV benefits of the different financing */ continued page 32*

Rooftop Solar

continued from page 31

options. Explain what that means.

MS. BUCHANAN: The developer should look at the present-value cost of buying the asset under the different structures. For example, we would not give him a fixed-price purchase option at the end of the lease. He will have to estimate what the market value of the equipment will be at that time and factor in how much he would have to pay, on top of rent, to have the asset for its entire life. Look at the termination value schedule in case the transaction is cut short. In a partnership, while maybe not quite as much capital is raised at inception, our share of the asset drops to 5% or 10% after we reach a target return. It costs less to buy us out after the flip than to take back the asset at the end of a single investor lease. The point is to compare the structures on an all-in basis.

Other Issues

MR. MARTIN: One of the biggest risks in this market is change in law. There is talk of potentially massive spending cuts, and perhaps also tax increases, to allow Congress to increase the debt ceiling. There is talk of corporate tax reform, perhaps pushing the corporate tax rate down to 25% and stripping a lot of these benefits from the tax code. How worried are you about change in law? How do you deal with it in transactions?

MR. VAN'T HOF: So far, there has not been anything really specific on the horizon. I think if there was something specific that was making its way through Congress, then we would want to incorporate it into the financing documents. However, we are not terribly worried at this stage. You need a lot of stars to align before Congress can act on anything today.

MR. MARTIN: Do you fix the corporate tax rate at which you value the tax subsidies at the current rate of 35%?

MR. BALCHANDANI: We do.

MS. BUCHANAN: It's a negotiated issue for us. We run sensitivities to see how much a change in rates will affect our return.

MR. MARTIN: Mit Buchanan, you said you do single-investor leases but you do not give the developer a fixed-price purchase option. Why not?

MS. BUCHANAN: It creates a compulsion issue in the view of our tax counsel. The market has moved. Several years ago, it was common to give an early buyout option or a fixed-price purchase option at the back end. The market has moved from that.

MR. BALCHANDANI: We have allowed early buyout options in some cases, so I don't think it is as large an issue for us from a tax perspective.

MR. MARTIN: Do you charge the developer for giving a fixed-price purchase option?

MR. BALCHANDANI: Yes. You strike it at a yield that would achieve a premium for us. Any fixed-price option limits our upside potential to an extent, so we have to get paid for that.

MR. MARTIN: Going back to the cost of capital. Darren Van't Hof, Mit Buchanan said that if you have to take an investment credit, it uses scarce tax capacity of the bank, and you have to charge for that. What do you think is the premium for investment credit deal over a Treasury cash grant deal?

MR. VAN'T HOF: I don't know, because we haven't gotten there yet. We are doing mainly Treasury cash grant deals.

MR. MARTIN: One of your colleagues said on this same panel in San Diego last fall that the only deals U.S. Bank will do next year are Treasury cash grant deals. Is that still the position?

MR. VAN'T HOF: No, that's not entirely accurate. It really isn't so much a tax capacity issue as a GAAP accounting issue of how the investment credit versus the grant affects book earnings. One of the ways to solve the problem is to move to sale-leaseback transactions. I am spending considerable time this year trying to develop a product within U.S. Bank that can manage the GAAP accounting issues. Developers should be aware that different investors have different sensitivities. We might care about one thing while JPMorgan does not.

MS. BUCHANAN: In terms of premium, it comes down to a market return. We have seen a range of as low as 25 to 50 basis points, but have also seen 125 to 130 basis points to take an investment credit rather than a cash grant.

MR. BALCHANDANI: This year where, for whatever reason, the grant is not available and we have to take an investment credit, we have looked at something like a 100-basis-point premium. That's today. I think when we get to next year — going back to the supply-demand question — the premium may be higher.

MR. MARTIN: There is a 100% depreciation bonus on most rooftop solar equipment put into service this year. Do you take it or do you make the developer opt out?

MR. VAN'T HOF: We don't like it that much. We elect regular MACRS depreciation.

MR. MARTIN: So you make the partnership opt out. Does anyone take the depreciation bonus?

MS. BUCHANAN: It is a negotiated point. At times, yes, we will. The problem is that taking bonus depreciation does not help earnings. In fact, because you are getting part of your return in additional tax benefits, you have to take a smaller share of cash to hold your yield constant. It actually hurts book earnings.

MR. VAN'T HOF: It is not as valuable as people think.

MR. MARTIN: President Obama was asked at a press conference yesterday whether he would be in favor of extending the bonus into next year. To you guys, it doesn't really matter. You are not that keen on it.

MR. VAN'T HOF: It has actually taken some liquidity out of the market. We syndicate to various utilities. They accelerated some of their capital expenditure budgets because of 100% depreciation bonus, and some of them are no longer customers on the sell side of our tax equity investments because of that. It took about $300 million in liquidity out of the secondary market for tax equity positions.

MR. BALCHANDANI: We look at the average life of our investments, and the bonus severely reduces the average life so it is not an optimal structure for us.

MR. MARTIN: We are down to the last queston. What are the two issues that take up the most time for you in rooftop and small ground-mounted solar transactions?

MS. BUCHANAN: One challenge is the amount of diligence that has to be done around the power contracts and offtakers. There is no such thing as a standard power contract or customer lease in this market. The other challenge is the development process is very fluid. Things fall in and out. As an investor, you cannot just do one-time diligence. It is an ongoing process.

MR. VAN'T HOF: When there is debt at the project level, intercreditor issues can oftentimes burn up six months. Due diligence is also a very real issue. A lot of people want you to start working on their projects maybe a little too early, and it ends up costing the developer if the project isn't ready because you know your lawyers are going to keep spending until you tell them to stop. The developer pays the legal costs.

MR. CAVALIERE: A big issue on the residential side is servicing — O&M — that has to go on for the full term of the lease. We are not in a position to operate and maintain the equipment ourselves, so you need to have backup servicers or at least know that you can get a backup servicer if the developer falls away. The servicer is important for another reason. It has to collect the monthly lease payments from customers and keep tabs on everything and ensure the accounts receivable are current.

MR. BALCHANDANI: The two biggest issues for us are the pipeline — finding enough transactions that meet the criteria that we have from a credit perspective — and figuring out how to do deals with so many individual properties efficiently so as to keep transaction costs at a manageable level. ◎

Latin America: How Big an Opportunity For Renewables?

The past two years have seen an explosion of activity in Latin America. A panel talked at the Chadbourne global energy and finance conference in June about whether the best opportunities are now south of the US border and the challenges of developing and financing projects in the region. The panelists are José Galindez, president of Spanish solar developer Solarpack, Michael Allison, managing director of Macquarie Capital Advisors, Morgan Landy, a senior manager with the International Finance Corporation, and Jared Brenner, executive director, Global Energy Group-Latin America with WestLB. The moderator is Rohit Chaudhry from the Chadbourne Washington office.

MR. CHAUDHRY: Jose Galindez, what are the key differences when you develop a project in the United States versus in Latin America?

MR. GALINDEZ: In the Un ited States, and also in Europe, political stability and discipline are taken for granted. When choosing where in South America to be active, you must choose a country that you expect to be stable for a while. The second difference is the currency. Power sector assets depreciate over very long periods. Make sure that the assets are denominated in hard currencies or in currencies that can stand long-term financing in local currencies.

MR. ALLISON: Securing title to land is more complicated than in the United States because land is often owned by the community. This is true in Mexico, for example. Security is another difference. When we were negotiating a construction contract for a wind farm in Mexico, we spent a lot of time talking about physical access versus legal access to the site. It is a small but important point. Another difference is resource differentiation. There is a lot less differentiation from one available site to the next today in the US market than there was five years ago. This is not true in Latin America.

MR. CHAUDHRY: Michael Allison, what / continued page 34

Latin America

continued from page 33

makes a market attractive to you? Jose Galindez mentioned political stability. What do you look for before diving into Mexico, for instance, or even more broadly into other countries in Latin America?

MR. ALLISON: Growth prospects are important. We do not want to go to an area, especially outside our home base, and do just one deal. We want to have the opportunity to do multiple transactions. A stable regulatory regime is important. How do we get our money out after we have invested? There must be a clear exit strategy. It is also important for whomever we are backing to have a local presence. Renewables are international in that capital and equipment comes from all over the world, but it is important that the developer have local roots. It is very hard to do fly-in and fly-out development. At Macquarie, we need a local office and people on the ground before we will feel comfortable investing capital.

GDP and demand for electricity are growing at 5% to 10% a year in Latin America.

MR. CHAUDHRY: Jose Galindez, you are doing projects in Chile and Peru. What makes those markets attractive and are there other countries in Latin America that you find as attractive?

MR. GALINDEZ: We started in Chile three years ago, and I think at the time, we were the only large developer doing solar there. Besides the reasons that I already mentioned — a stable politcal system and convertible currency — Chile has perhaps the best solar resources in the world. Electricity prices are high enough in areas where there is a high consumption of electricity, like the north where the mining industry is located, to make solar energy economic. All of these factors make it a very attractive market, although the size of the market is not large. We have to take into consideration the sizes of the markets we are talking about: Chile and Peru are much smaller opportunities than Brazil and Mexico.

Toughest Issues

MR. CHAUDHRY: Mike Allison touched upon this in his earlier response when he talked about Mexico. What are the toughest issues you face in trying to develop projects in Chile and Peru?

MR. GALINDEZ: The issues are not very different from the ones we have faced in Spain or we are still facing in France. You have to deal in some cases with land that is government owned. It is time consuming to get permission to use it. Interconnection is maybe the largest developing nightmare all over the world. Those are the two main challenges. When it comes to getting a power contract, Peru and Chile are different. Chile is driven by the private sector. The government tries to intervene as little as possible, and the market is responding to a very light policy of encouraging renewable energy. Peru is more state-driven, so you get a power contract, if at all, in a government auction.

MR. CHAUDHRY: Morgan Landy, the International Finance Corporation has financed projects all over Latin America. What are the toughest issues you see as a lender when trying to finance these projects?

MR. LANDY: Our goal as a member of the World Bank Group is to support the energy sector in these countries. We have to start by asking what alternatives each country has besides renewables. Each country has a different profile in terms of the history and politics. For example, in Mexico, which has some of the best wind resources in the world, the IFC has had done two transactions — a 250-megawatt plant and then a 67-megawatt plant — in the past two years. Each country has made a different policy decision whether and how to promote renewable energy. Mexico does not have a feed-in tariff, but because the wind is so strong, wind developers can compete effectively with the alternative sources of power. Chile has a fully deregulated market. The government has put in place a renewable energy purchase obligation for big utilities, so the utilities must buy, but a developer is not guaranteed a price.

It really comes down to resources first and then regulation. For example, wind is fantastic in Mexico, solar in Chile and hydro in Brazil. Once you confirm the existence of the resource, what is the role for the particular technology and what is the government support mechanism? We have heard a lot about the political aspects of investing in renewables in the United States; public policy support for renewables waxes and wanes. It is the same in every country. If you can't figure out the politics around the regulations or the subsidy or the feed in tariff, you are really at risk. I agree that when doing business in a place like Latin America, Eastern Europe or any emerging market, you need to get close to the local players to make sure you are not making a mistake.

MR. BRENNER: I agree with Morgan Landy; the regulations vary considerably from one country to the next. However, in all of these countries, you have had a relatively stable regulatory regime for a number of years that has survived several changes of government. We take comfort from that, but we also recognize the risk of backtracking, as we have seen in Spain and Italy recently. I don't see Latin America as any different from Europe or the United States in that respect.

Power Contracts

MR. CHAUDHRY: Renewable energy projects are facing some significant headwinds in the United States. It is difficult to get a long-term power contract to sell the output. Do you see similar issues in Latin America?

MR. GALINDEZ: With the exception of Chile, all the rest of Latin America is driven by state auctions for PPAs. You have to wait until there is an international tender like the one last year in Peru. In Brazil, there was the first reverse auction in wind, and we are expecting one in solar sometime soon. There is little opportunity, apart from Chile, to do a purely private transaction.

MR. ALLISON: Latin America is a relatively small and new market. Renewables are only a couple of years old in these countries. While electricity is sold for the most part through government tenders, the market is transparent. There are a number of creditworthy developers already on the ground in the region. The competition is high.

MR. CHAUDHRY: Morgan Landy, you have a good view of the entire region. Where are the opportunities for renewable energy developers?

MR. LANDY: A lot of the renewable energy development that we have seen in Latin America has been hydropower. Given the significant resource endowment, renewable energy has been a traditional source of power, but it is also an important part of the future. Whether it is large hydroelectric facilities in Columbia and Brazil or small hydro projects in Peru and Chile, we see a lot of opportunities for new investment there.

Moving beyond hydro, the next most active area we see is wind, where there are about 2,000 megawatts already installed in Latin America. The bulk of that is in Brazil and Mexico. Solar is just beginning to show some life. As Jose Galindez mentioned, his company is really a pioneer in getting solar projects done in Chile and Peru. In geothermal, we financed our first geothermal plant recently in Central America in Nicaragua. The west coast of Latin America sits atop a ring of fire; there are plentiful geothermal resources stretching from Chile all the way up through Central America, which is potentially a fantastic resource for the region.

In Brazil, there have been government auctions of power contracts. The auctions have attracted a huge amount of interest, but primarily from local investors. The financing is largely guaranteed by the Brazilian Development Bank and is long-term financing in local currency. From an investor perspective, if you take the financing risk off the table because the Brazilian Development Bank is there to finance all projects, then you are really just bidding on equity risk. Investors seem willing to take relatively low returns.

In Peru, the situation is different. You have cheap natural gas that is heavily subsidized by the government. The challenge for solar, wind and even hydro is how you compete with electricity generators who are using subsidized gas. The government set up auctions by technology, for example, by taking bids of 500 megawatts of hydro or 200 megawatts of wind or 60 megawatts of solar. The plan is to have a diversified mix of energy.

In Mexico, it is different again. The market is much more competitive. It is up to each bidder to come up with an offtake agreement. In the two deals we financed recently, the power contracts has terms of 20 to 25 years. One was in US dollars, and one was in pesos. The financing mirrored the power contracts. In offtake with Cemex, the big Mexican cement company, the offtake was in dollars and the financing was in dollars. We had to raise local currency funding to finance the peso power contract. A key part of the risk matrix for that project was not so much the cost of the funding, but can one get liquidity in long-term pesos. / continued page 36

Latin America

continued from page 35

The point is that the situation varies by country. The best thing a government can do is to run an auction and then take steps to reduce the risk profile.

MR. ALLISON: Seventy percent of electricity generation in Brazil is from hydro and is obviously inexpensive. Electricity prices run from $13 to $30 an megawatt hour. Having that proportion of your generation mix in a single fuel source is risky and has led to periodic blackouts There was a blackout earlier this year that affected 2.5 million people in São Paulo and drove prices to $340 a megawatt hour. When Brazil went out for tenders in 2009, the backup fuels to hydro were fuel oil and gas. Fuel oil power contracts were written at $390 a megawatt hour and gas at $94 a megawatt hour. The wind tender, in comparison, came in at $84 a megawatt hour. While there is no direct subsidy for these renewable technologies in these markets, they are certainly cost competitive when you think about them as an alternative fuel source.

MR. CHAUDHRY: Jose Galindez, what level of tariffs are you seeing in Peru and Chile?

Mr. GALINDEZ: Our power contract in Peru is public because it was awarded in an open auction. It was at $210 a megawatt hour in February last year. We expect prices in future power contracts will be lower because the cost of the equipment is falling.

The contracts in Chile are private. We are now building a 1-megawatt project for Codelco that has sparked an interest in solar among other mining companies and has led to some private company auctions in the northern part of Chile. We believe market prices for solar in northern Chile are in the low teens.

MR. CHAUDHRY: Do you have sense for where electricity prices are for wind?

MR. GALINDEZ: In Chile at least, the wind resource is less competitive than solar. The insolation levels in the northern part of Chile are 50% higher than in the central valley in California.

MR. CHAUDHRY: Mike Allison, what tariffs are you seeing in Mexico where Macquarie has a wind farm?

MR. ALLISON: I don't want to "out" our power contract in public, but . . . .

MR. CHAUDHRY: The neighboring project — what is it being paid?

MR. ALLISON: Its contract is above $100 a megawatt hour. These are projects where the offtaker is buying power at a discount to the power that is available in the spot market. While the price seems high, there is a huge economic incentive for consumers of energy to buy this power.

MR. CHAUDHRY: You told me yesterday that there is no solar development in Mexico. Why is that?

MR. ALLISON: The cost of solar is too high. Solar developers are not in a position to offer electricity at a discount to the current market.

Resource Data

MR. CHAUDHRY: Let's talk about resource studies, which are very important for renewable energy projects. What kind of resource data do you see in different jurisdictions in Latin America? Is it of a quality and of a duration that makes you comfortable to do projects there? What about solar resource data?

MR. GALINDEZ: We do not see much difference from what we have in other places. We always try to check the satellite database with local meteorological stations, although there are areas of Chile and Peru without many such local stations. We do not feel uncomfortable with the data we have or with our experience in translating satellite data into actual production.

MR. CHAUDHRY: And for wind?

MR. ALLISON: In wind, we can usually get good meteorological data of sufficient duration. However, the maps and long-term reference data are not as good quality as in the United States.

MR. CHAUDHRY: Jared Brenner, what resource data do lenders typically want when financing a project? What do you require when you do a wind or a solar project in Latin America?

MR. BRENNER: We look for a minimum of two to three years of on-site data and a longer period, if possible, of correlative data — especially for a wind farm. As was just mentioned, the correlative data is often lacking, so what we are sometimes forced to do is commence work on the basis of an exceptional resource report but require wind data collection to continue while we are working on the financing with the understanding that everything will be reevaluated prior to closing when there will be another six to nine months of additional data.

MR. CHAUDHRY: Morgan Landy, do lenders discount the data because the quality may not be as good as in other regions or do you give full credit for the data?

MR. LANDY: It works the same as in the United States. We hire an independent consultant to review the data. The lender's best case is always based on a revised cropped number. As the valuations get higher and higher, and people realize the extent to which the quality of the data contributes to a higher valuation, I think greater effort will be put into maps and data collection in the region. A market will develop. Developers who do the proper homework can borrow a higher percentage of the project cost. Debt is cheaper capital than equity.

MR. CHAUDHRY: Do you see development agencies like the World Bank contributing toward the cost of resource mapping across countries in Latin American?

MR. LANDY: The IFC is a private part of the World Bank, and our job is to finance private investment either as a lender or equity investor in the developing world. We generally do not cover the costs of resource mapping, but our colleagues at the World Bank, which works with governments do provide this type of support. There are also other donor-type agencies that are helping governments do resource maps.

Government Support

MR. CHAUDHRY: Let's move onto the next topic: government support. The sense I am getting from this panel, based on initial comments, is that there really is not much need for government support for renewable enegy projects in Latin America. Jose Galindez, do you agree?

MR. GALINDEZ: It is very important in Chile to require that at least 5% of electricity come from renewable sources. Apart from Chile, I think we are still some years away from doing renewables without subsidies. The resource is so amazingly good, particularly for solar, all over South America, from Chile up to the north of Peru, that we are so close, but not yet without government support

MR. CHAUDHRY: Morgan Landy, you mentioned that your projects in Mexico were done without government support. How critical do you think government support is in different jurisdictions in Latin America?

MR. LANDY: Maybe I should restate. In the Mexican deals we closed, we did not have direct support from the government, but it was important to have a regulatory framework to allow the wind farms to connect directly to grid and to be able to draw backup power from the grid, if necessary. While we did not get direct financial support from the government, the enabling environment to make sure that wind could fit into the system and to give it a reasonable chance of getting a reasonable power contract was critical.

We see more and more interested pools of soft money and grants for clean energy in the emerging markets. There are important policy questions in the region: Who will pay for electricity from wind or solar if it costs more than electricity from coal or gas? Is it fair to put the burden of diversifying on the consumer? There are growing pools of money. We use some of it in Mexico — something called the Clean Technology Fund where we put in deeply-subordinated debt to help reduce the capital cost of projects, which helps make the projects more bankable and lowers the tariff that otherwise would have to be charged. We see more such money becoming available for solar.

MR. ALLISON: Mexico has a postage stamp-type rate for transmission where you pay the same price no matter how far the electricity is transported. If that goes away, then wind projects would be unlikely to offer their electricity at a discount to the CFE standard rates. The point is there is indirect government support that is critical to the projects.

MR. CHAUDHRY: Government support can be withdrawn as we have seen in Spain and Germany, even for projects that are already in operation. To what extent does this political risk factor into your analysis of doing projects in Latin America?

MR. BRENNER: It factors in, but we do not view Latin American countries any differently than any other country in terms of this risk. It is present everywhere in the world. What happened in Spain and Germany is that the programs were open ended and created bubbles. There was overdevelopment. The subsidy started to distort the market. In Latin America, we are still at the very beginning of the development of renewables. Take the project that we are working on in Peru with Solarpack as an example. The contract price for electricity is more than $200 a megawatt hour in a market with abundant electricity from hydro and gas that can be purchased at 25% of the solar contract price. The solar development underway currently is less than 1% of total system demand. It is too small to distort the market. It is not a burden. Cost might become a factor down the road, but at this point, we are pretty comfortable that government support will not be withdrawn.

Financing Challenges

MR. CHAUDHRY: Let's move to financing of projects. Jared Brenner, you told me some time ago that no renewable enegy project in Latin America, and maybe even in any emerging market, had closed with purely commercial bank financing. Is that still true? Or have commercial banks, without agency support, now closed renewable projects in Latin America?

MR. BRENNER: There are at least two / continued page 38

Latin America

continued from page 37

wind deals in Mexico that are being done without agency support. In the countries we have been talking about, it is largely a question of economics and what makes the most sense for the developer. The banks are not requiring some sort of quasi-political risk coverage to get comfortable.

MR. CHAUDHRY: Morgan Landy, in terms of the scale of the market, how many renewable energy deals have agencies closed in Latin America?

Other than in Chile, the only way to get a power contract is through a state auction.

MR. LANDY: Latin American is really lagging behind other regions. For example, the United States has 40,000 megawatts of wind; Latin America has 2,000, and Asia has about 70,000, with China being a huge part of that.

There is some perceived regulatory risk. Organizations like IFC play a role to get the first deals done. Mexico is a good example where, one or two years ago, the IFC was involved with financing some of the first deals to help work out the regulatory issues, and now we see deals getting done without agency participation. We see our job as moving to the frontier and going to Peru or Central America or Colombia, where the next developments have to take place and the banks may be more nervous. That said, we see a fair amount of liquidity, even in what would be considered more exotic countries like Peru, which adopted the very well-developed regulatory regime in Chile with which the banks are comfortable.

MR. CHAUDHRY: Is it true that renewable energy projects are being financed on a merchant basis in Latin America?

MR. LANDY: In Latin America, IFC is financing between three and five renewable energy deals every year. Some of them are very small. Some are larger. They are project financings or corporate financings or even start-up equity investments in small, renewable developers in the region. In Chile, we financed a 50-megawatt merchant plant about two years ago. The project is selling its electricity on the spot market, so we did a lot of modeling of the market and we put on a very conservative debt-to-equity ratio, structured to protect the lenders against downside price risk, but it made sense for the equity, given the high prices currently in the market and the view that the government's incentive program will remain in place. It is possible to do a merchant plant, although it is obviously not easy, and many of the commercial banks remain uneasy with merchant projects based on experiences elsewhere.

MR. CHAUDHRY: Jared Brenner, are merchant financings unique to Chile?

MR. BRENNER: We do not see a trend toward merchant financings in Latin America. The commercial banks still want to see at least 50% of the output contracted. There was a fair amount of risk in the Chilean project to which Morgan referred. I do not think our bank would have been comfortable with that level of risk. The bet the IFC made worked out very well given the drought in Chile, but if there had been more water, it might have been a tighter situation. Agency support was essential to get that project financed.

Outlook

MR. CHAUDHRY: Where do you see the renewables markets in Latin America headed in the next five to 10 years?

MR. GALINDEZ: We will see an expansion in several key markets. Chile will grow to 13,000 megawatts, Peru maybe to 6,000 or 7,000 and other countries, like Brazil and Mexico, will reach a much larger scale. We will also see a bigger selection of investment-grade countries rather than speculative countries.

MR. LANDY: The opportunities are going to get bigger and bigger in Latin America for renewables. You have abundant resources in wind, solar and geothermal. The cost of equipment is declining. IFC is also investing in solar manufacturing facilities in Asia that hope to sell into Latin America. As equipment costs fall, renewables will become more and more attractive. The biggest risk to renewables, not only in Latin America but also in the United States, is shale gas. Potential investors in the sector are still thinking about how to hedge against that risk. But overall, I see opportunities and more investors and banks will start taking Latin America more seriously as governments open up opportunities.

MR. ALLISON: At a macro level, we see 5% to 10% annual GDP growth in the region. We see demand for electricity growing at about the same pace. Brazil is expected to need a 70% increase in generating capacity by 2019. With 65 million people in the region who do not have access to stable electricity at home, there is obviously opportunity in those markets.

MR. BRENNER: I agree. GDP and load growth in the region are outstripping growth in North America and Europe. Latin American governments are moving to integrate renewables into their systems on the basis of environmental benefits. As costs equalize, there will be even more such projects. ◎

Negotiating With Chinese Lenders

by Magnus Rodrigues, in London

Chinese lenders are emerging as a major source of funding in international project finance transactions.

Developers in various sectors in Asia, Africa, Australasia, the Middle East, Europe and the Americas now routinely consider the option of using Chinese equipment with financing from Chinese lenders.

The most active Chinese lenders in financing projects outside China historically have been the Export-Import Bank of China and China Development Bank. In 2009 and 2010, these two institutions lent at least US$110 billion to developing countries, which was more than the World Bank. Both are state-owned policy banks indirectly focused on funding projects outside China. Policy banks were established to pursue macro policies of the Chinese government. However, China Development Bank is in the process of changing from a policy bank to a commercial bank.

Various other Chinese commercial banks have financed or considered financing international projects. The four largest Chinese commercial banks — the Bank of China, Industrial and Commercial Bank of China, China Construction Bank and Agricultural Bank of China — are now four of the seven largest banks in the world by market capitalization.

Although the structure of Chinese banking is evolving and each Chinese lender has its own traits, there remains a high degree of uniformity in the approach of Chinese lenders.

Practical Considerations

Due to the very large size of Chinese lenders and because their networks are spread over a considerable area even within China, work on project finance transactions is conducted by various branches of each Chinese lender. Where a Chinese lender is providing an export credit facility to facilitate sale of Chinese goods in a project finance transaction, the branch of the Chinese lender involved will typically be the one that works most closely with the relevant Chinese vendor that is supplying the goods. This has the advantage that the branch will understand the relevant sector in which the Chinese vendor operates very well, but there is no one central team within the larger institution that acts as an experienced project finance desk.

The branch may be more familiar with financing of projects within China where some practices are very different. For instance, it is not unusual for Chinese lenders to require a completion guarantee for financings in China. More time may have to be spent with Chinese lenders — including time on the ground in China — educating them than with other international lenders.

The approval process for Chinese lenders can be more time consuming and structured than for other international commercial lenders. For instance, the Export-Import Bank of China and China Development Bank are usually only able to complete their final approval processes when all the contracts have been agreed. This means that the financing agreements will not be able to be signed as soon as they are agreed.

Chinese lenders will usually have the benefit of a Sinosure insurance policy in international projects where Chinese lenders are financing the purchase of equipment or other goods from Chinese manufacturers. Sinosure, which is short for China Export & Credit Insurance Corporation, is China's policy-oriented insurance company specializing in export credit insurance.

Larger Sinosure transactions require the approval of the State Council, which is the executive arm of the Chinese government. This can potentially take a number of months.

The policies of the Chinese central bank */ continued page 40*

Chinese Lenders

continued from page 39

— called the People's Bank of China — remain of central importance for Chinese lenders. This is not necessarily a negative influence at present. The People's Bank of China remains supportive of Chinese lenders lending overseas. The policies of central banks in many developed countries, such as implementation of Basel III, are forcing many western banks to reduce their lending.

Chinese lenders are becoming a major source of financing for infrastructure projects.

Types of Projects Financed

Since the 1990s, projects have been financed within China across a range of sectors. The sectors include power, transportation, and mining and metals projects.

The first wave of Chinese lending outside China by Chinese policy institutions — the Export-Import Bank of China and China Development Bank — reflected Chinese government policy of using economic assistance as a key foreign policy tool. For instance, during 2009, China EXIM and China Development Bank provided US$60 billion facilities for oil to Kazakhstan, Turkmenistan, Russia and Venezuela that furthered the Chinese government's aim of securing supplies of vital natural resources for the resource-hungry Chinese economy.

With Chinese lender entrance into the broader project finance market, Chinese lenders have been prepared to consider financing projects in developed countries as well as emerging market countries, including India, The Philippines, Oman, Botswana, Saudi Arabia, Turkey and Guyana.

Chinese lenders are prepared to lend much higher amounts to a wider range of countries than other international lenders. This difference is most marked with regard to various emerging markets.

For instance, China Minsheng Banking Corporation, which is a large commercial Chinese bank, earlier this year offered to provide a project finance facility for the development of a US$600 million alumina facility in Laos. This alumina facility is being developed by a joint venture of Orde River Resources of Australia and Non-Ferrous Metal Industry's Foreign Engineering & Construction of China.

The project finance structures in which Chinese lenders are prepared to lend has significantly evolved during the last few years. Initially and for many years, Chinese lenders focused on lending to projects in China where the sponsors and other parties would be all Chinese or a mixture of Chinese and non-Chinese parties.

When Chinese lenders started to lend outside China, their initial focus was financing projects where most of the key parties were Chinese, but this has since evolved so they will now lend to projects where even only one party is Chinese (for example, where equipment is supplied by a Chinese vendor or there is a Chinese investor).

More recently, they have been prepared to contemplate lending to projects where none of the parties is Chinese. For instance, the Nakilat Phase III LNG project sponsored by Qatar Gas Transport required US$949 million in debt facilities for construction of 25 ocean vessels specially designed to transport LNG from Qatar's North Field. Bank of China and China EXIM each provided a US$200 million facility as part of the US$949 million facilities. There are no Chinese sponsors, vendors or offtakers (although, like many others, Chinese parties do purchase LNG from Qatar).

However, it will remain an anomaly to see Chinese banks financing deals in which there is no other tie to China. For instance, at the end of 2010, CLP successfully refinanced US$288 million of the debt for the 1,320-megawatt Jhajjar coal-fired power project in India. This involved replacing some of the debt that was to be provided by Indian lenders with a Sinosure-backed export credit facility provided by China EXIM and China Development Bank together with another facility provided by other international commercial lenders. In this project, the construction contractor is the Chinese company Shandong Electric.

Diligence by Chinese lenders can take longer than for other lenders if the Chinese lenders have limited experience with the type of project.

Financing Terms

The availability of project finance facilities from international commercial lenders remains different from what it was before the financial crisis in the fall 2008.

In contrast, Chinese lenders continue to have the ability to provide very large facilities and are, therefore, able to fund deals alone or with a very small number of other lenders. This is a very important advantage in dealing with them and avoids the protracted and often difficult nature of a club or syndicated financing.

When lending outside China, Chinese lenders will generally expect their facility agreements to be governed by English law, and the terms and conditions of such facility agreements usually follow market practice within the London banking market.

One benchmark with which Chinese lenders are comfortable is the template financing agreements prepared by the Loan Market Association in London. These forms of agreements have been prepared taking into account the views of key parties involved in the London banking market in a manner that is meant to balance the interests of borrowers and lenders.

Chinese lenders are subject to the policies of the People's Bank of China as well as, to a degree, those of other parts of the Chinese government. Compared to controls on international lenders in Europe and the United States, those in China are stronger overall. Indeed they may be more analogous to those in other emerging markets. For example, the Reserve Bank of India imposes various controls on the operation of Indian banks. To provide an illustration of such policies, recently the People's Bank of China has started to promote lending in renminbi outside China, and this practice is likely to become more important as the ongoing re-evaluation of the US dollar and other major currencies continues.

Where the financing is linked to a Chinese equipment supply or other contracts, the terms of the financing will usually include certain terms that reflect this position. For instance, these terms may include a cap tied to the percentage of the Chinese goods that will be financed with the loan facility.

Chinese lenders often have a different risk perspective from other international lenders when considering projects. As a result, they can be more open to accepting solutions that would be more difficult for other international lenders to accept. For instance, on a recent bid for a North African power project, the European sponsors spent many months making limited progress negotiating with European banks, which were concerned about certain of the commercial aspects of the project. Finally the sponsors gave up and turned to Chinese lenders that agreed to provide financing in a matter of weeks, thereby enabling the sponsors to submit a bid in time. ◎

Policy Quagmire: What Next?

Global clean energy investment fell 34% in the first half of 2011, weighed down by low natural gas prices in the United States and subsidy cuts in Europe. However, by the third quarter 2011, it had turned into a 16% increase, helped by falling costs for solar panels and wind turbines. Energias de Portugal and Electricité de France folded renewable energy subsidiaries that they took public just three years ago back into the parent companies. The US is unlikely to act on carbon. The political parties are at the loggerheads over an energy policy. A "super committee" of 12 members of Congress is supposed to find a way by November 23 to reduce the US budget deficit by at least $1.2 trillion.

What is the market likely to look like over the next two years if public policy remains stalled or, even worse, there is backtracking on support for renewable energy? In the longer term, what renewable energy technologies have the best chance of standing on their own without public policy support?

A panel discussed these and other subjects at the Chadbourne global energy and finance conference in June. The panelists are Bill Green, senior managing director of Macquarie Infrastructure and Real Assets (MIRA) Inc., Joseph Slamm, managing director of Hudson Clean Energy Partners, and Stephen Herman, managing director of Energy Capital Partners. The moderator is Eli Katz with Chadbourne in New York.

MR. KATZ: Bill Green, with all the headwinds facing renewable energy, why is it still an attractive space for you?

MR. GREEN: The simplest way to think / continued page 42

Policy Quagmire

continued from page 41

about it is that until we invent cold fusion, there are four ways to generate power on this planet: coal, nuclear, natural gas and an assortment of renewables. Each of these strategies at the macro-level has challenges, and those challenges are different in every part of the world. In the United States and Canada, it is difficult to site a new coal-fired power plant. Nuclear has proven itself to be very expensive. Those costs are only going up after Fukushima, so that leaves us natural gas —abundant, relatively clean — and renewables. Our view is that, despite the short-term blips on the radar screen, renewables and gas are the foundation of forward generation.

MR. SLAMM: The headwinds come from a number of different places, not the least of which is we are now in a down cycle on commodities. We are also in a volatile period in terms of public policy as a consequence of the stress in the overall financial system and markets. We are in a transition phase of moving toward economies of scale that will allow renewable energy to compete head to head with fossil fuel. The world has changed from even a year and a half ago. Budgets and jobs are the main focus for public policymakers.

The long-term fundamentals of renewable energy have not changed. Headwinds can be a good thing. GE and Siemens are squeezing 20% more output compared to a few years ago out of the same wind turbine gear boxes. Necessity leads to invention.

Change-in-Law Risk

MR. KATZ: Let me make the question a little harder. Steve Herman, my sense is that not only have people stopped talking about climate change in Washington, but they have actually started becoming a little negative on it. There is even some backtracking at the state level. How do you deal with that uncertainty as you make investment decisions?

MR. HERMAN: "Cap and trade" has become a term of derision almost like Obamacare. We get very granular. How can we make this project work? Yes, we have to assume risk — we are not in the government bond investment business — but we evaluate everything, assign a probability, look for creative ways to address the some risks, and perhaps decide to assume others.

Private equity funds are bullish in the longer term about the prospects for solar thermal.

MR. GREEN: Let's also get granular about policy uncertainty. Here are a few "on the ground" realities.

Thirty states have mandatory renewable portfolio standards. The biggest challenge to these RPS targets came in the last election cycle in California where a group of well financed oil companies and others got together to overturn AB 32, the climate change statute in California. The effort was dressed up as citizens in favor of job creation. It lost. The loss was important because, as a citizen vote, it basically gave us a bellwether of how the RPS would fare. I don't know whether we will ever see a national clean energy standard, but there are 30 states today with such standards covering a majority of the US electricity market.

Point two: what happens these days on Capitol Hill is a tremendous amount of posturing. We can talk about the macro policy issues all day long, but development is fundamentally a local game. Things happen at a local level. They are driven by local needs, transmission, demand for power and utility politics. Will Sarah Palin be president? Will we build renewables? On the ground, when we go to work on Monday, the question is: are power purchase agreements still being issued? Yes. Can the good developers get them? Yes. Are there still a lot of developers? Absolutely. And does that create an environment where we can build and finance new projects? Yes.

MR. HERMAN: To illustrate Bill's point, the day before yesterday the Illinois legislature passed, by veto-proof margins, a bill that will allow two coal gasification plants — making pipeline-quality gas — to be built in Illinois, effectively guaranteeing a price of $9+ an mcf. This is important to Illinois because the state has a lot of coal. It is a jobs bill for the state. The bill had broad support from both Democrats and Republicans.

MR. KATZ: Let me ask a specific policy question about the Treasury cash grants for renewable energy projects. The deadline to start construction of remaining projects to qualify for grants is the end of this year. The current betting is that the deadline will not be extended. What happens when the cash grant goes away?

MR. SLAMM: Cash subsidies are more efficient than tax subsidies. A little known fact is that developers waste 30% of the tax subsidies converting them into current cash in the tax equity market.

My partner, Neil Auerbach, will be talking on Capitol Hill tomorrow about a bill that is supported by no fewer than 80 Republican congressmen — and, interestingly enough, the conservative think tank the Heritage Foundation — to form a trust fund patterned after the trust funds that were used to build the interstate highways and broadband in the United States, fund it with a surcharge on oil and gas and actually pay cash for renewables. It is getting a lot of traction on the Republican side because it is budgetary neutral, which is the name of game right now. I do not think either political party is against clean energy. The key is to get the most clean energy at the lowest cost.

MR. GREEN: I think in the near term the end of the cash grant program will cause some panic, but we were building renewable energy projects well before there was a cash grant.

MR. HERMAN: I am sorry if the grants disappear, even though the fact the program is ending is creating opportunities for us since we have money to lock in to help developers start construction. But let's assume the program disappears. Either costs have to come down or consumers will have to pay more for electricity if they want the country to rely more heavily on renewable energy. Renewable energy projects will be more expensive to build. Developers will have to pay more to cover the capital costs of their projects. There may be ratepayer backlash if prices in PPAs increase.

MR. KATZ: Why would utilities sign out-of-the money PPAs if you do not force them to do so?

MR. HERMAN: It will fall back on the states to decide how important this is as a matter of local policy, just as Illinois decided to promote coal gasification projects. The state was willing to have gas consumers pay $9 for gas to create more demand for Illinois coal. Now, maybe $9 gas does not quite do it, so the developer will then have to go to the supplier of the gasification equipment and the EPC contractor and say, "Let's work together. How are we going to make this work at $9?" If they have other opportunities, they may say, "We don't want to do this." Or if they need the business, they may say, "We will work together to figure out how to do this, and we will take some of the risk with you."

Opportunities

MR. KATZ: That is the free market solution. However, we are not sitting in a room full of people who work in renewable energy because of a free market solution. Joe Slamm, looking ahead, Hudson seems really good at getting into portfolio companies early and then exiting nicely. How do you assess new technologies, and what sorts of opportunities do you think will be big over the next two to three years?

MR. SLAMM: We have a very simple method. It is maximum efficiency and lowest cost. Suppose we are looking at a value chain company that makes a widget. We have invested in a couple of solar manufacturers, and their goal is to reduce the cost of their products. That is what we want them to do. Whether the company is a manufacturer or a project developer, the lowest-cost producer wins. Lower costs mean higher demand for the products.

Look at what Germany has done with its solar tariff. The tariff was scheduled to step down every three years. We don't do that here. We ask for the same subsidy every year. Now that the commodity cycle is low, the commodity cycle is doing it for us, but the federal side is not doing it yet.

We were building wind farms in 2001 with wholesale electricity prices of $20 to $29 a megawatt hour. It worked because the equipment was half the price that it is today. As the commodity cycle went up, natural gas prices started going through the roof, and GE said, "Thank you very much. I'll take that!" and made a lot of money during that period. Now that trend has reversed. The first thing that GE and Siemens did was to say, "Okay, instead of cutting margins, we are going to increase the efficiency of the machines." Could they have done that five years ago? Sure. Why didn't they? Because the margins did not require it.

My partner, Daniel Gross, says the margins in solar up and down the value chain are still approaching somewhere in the 40% range. Manufacturers in other industries are in the 10% range. There is still room to go. Policies that promote cost efficiency and innovation win. We get eventually to the point where there is no longer any policy debate, / continued page 44

Policy Quagmire

continued from page 43

and we are just competing on "We have the best machine, we have the best wind resource, we have the best geothermal resource." We are moving in that direction a lot faster than we thought.

MR. KATZ: Steve Herman, where do you think the big opportunities will be two and three years from now?

MR. HERMAN: To answer your question directly, I don't think it is useful to try to pick whole classes of investments that will be winners. Yes, we all make these judgments, and I may spend the next month looking at companies in a particular market because I think something will come of it, but you really can't pick classes. You have to pick within classes.

You start with a thesis. Let me give an example. Suppose you decide renewables are the place to be, but wind and solar are hampered by their intermittency, so the way to go is biomass. No one has done much biomass recently. The capital costs are very high per installed megawatt, but biomass is a very broad term. For example, it covers waste energy. We are trying to find a suitable technology. We are not venture capitalists so it has to be proven to some extent. It must be a technology that will allow biomass to compete in a particular location given a lot of different facts. We are spending tremendous time learning about technologies that have been deployed in other parts of the world that can now be deployed here. It is a long process.

After several months of study, I may throw up my hands and say that the current conditions do not allow for it, but I am not ready to dismiss biomass just because it has high capital costs and wholesale electricity prices are down. We are willing to invest the time to explore whether there are any unique circumstances, and we like the fact that few others appear to be putting in the same effort.

MR. KATZ: Quickly Bill Green, pick a winner: is it solar over wind? Is it a particular segment of solar?

MR. GREEN: I am bullish on solar thermal. I think turning photons into electrons at low cost and integrating storage has enormous potential. In the next two to three years, we should see more commercially-proven technologies emerge.

MR. HERMAN: I agree with that. When we first got into solar, we thought solar thermal was the way to go. We found PV was coming down quickly in cost, so we switched to PV, did well and exited. But one of our key people said solar thermal is going to come back because it has much more flexibility than PV. The utilities recognize that there is more dispatch ability with thermal solar. They can only take so much PV, and people are going to figure out how to get the costs down to compete with PV. It is just a matter of time.

US Inbound Investment Strategies For Renewable Energy

by Keith Martin, in Washington

A new wave of Chinese, Spanish and some other European and Latin American companies is investing in US renewable energy projects. Much of the attention is focused on the solar sector, but there have also been some notable recent purchases of interests in operating wind farms and other wind projects nearing the start of construction.

An issue for non-US companies investing in renewable energy projects in the United States is how to structure the investments.

The answer depends on the particular facts, but a good default position is the following:

Hold each project through a separate Delaware limited liability company (unless the business is rooftop solar installations or other forms of "distributed" energy, in which case it may be better to pool multiple projects in a single holding company).

File a form with the US tax authorities within 75 days after the Delaware limited liability company is formed to treat it as a corporation for US tax purposes.

Take care in what order assets accumulate in the LLC.

Make sure that at no point is 50% or more of the value in assets that are considered US real property.

Consider capitalizing the company with three parts debt to two parts equity.

View this default position as a working hypothesis. Test whether the overall tax burden not only in the United States, but also in the home country of the investor, can be reduced by tweaking the structure.

This article is aimed more at foreign companies and private equity funds investing in the United States than individual investors. Many of the basic principles are the same, but there are additional complications — and opportunities — for individual investors. (One of the more frustrating truths about the US tax laws is that the rules are often more complicated for individuals than for large corporations.)

Initial Challenges

Europeans warmed more quickly to renewable energy than the Americans did. European companies built up impressive early experience with wind and solar projects and new waste gasification technologies.

When demand for renewable energy began to grow more rapidly in the United States in the early part of the last decade, Europeans initially found several things daunting about the US market.

One was the complexity. Each of the 50 states and the District of Columbia, an enclave where the national government is based, has its own public utility commission that regulates electricity supply, and each has its own tax rules. Taxes at the federal level can reach close to 55% on the operating earnings that a foreign investor might earn from a US project, and there are additional state and local taxes to pay.

The other issue was that the US government subsidizes renewable energy projects heavily through the tax code. The federal government pays currently 56¢ per dollar of capital cost of solar projects, at least that amount for wind and geothermal projects, and slightly less for biomass projects through tax subsidies. New foreign entrants come without a US tax base. This puts them at a disadvantage when trying to compete with the incumbent US utilities.

However, they soon realize that regulated utilities are not the main competition. Most renewable energy development is by unregulated independent power companies, few of whom can use the subsidies either. Most of these developers essentially barter the tax subsidies to large banks, insurance companies and other "tax equity" investors in exchange for capital to pay part of the cost of their projects. There are currently 18 active tax equity investors and three basic tax equity structures in use, with many variations on the basic structures.

US Holding Company?

It is usually better to hold US investments through a US holding company than to invest directly from abroad.

There are at least three reasons.

First, investing directly will cause the foreign company or investment fund to be considered engaged in a US trade or business and require it to file US tax returns as if it were an American company.

US renewable energy projects are almost always owned by special-purpose limited liability companies that are transparent for tax purposes, meaning there is no US income tax at the project company level. This allows tax subsidies on the projects and earnings to pass through to the owners of the project company. It is important for being able to raise tax equity to help finance the project.

A foreign company or investment fund investing in such a transparent entity will be considered engaged directly in a US trade or business and become subject to US income tax at a 35% rate on its share of net income earned by the project company. The foreign owner will have to file US tax returns. It will be taxed on its share of income whether or not any cash is distributed to it. If the project company has more than one owner, then the project company will be treated for US tax purposes as a partnership and be required to withhold income taxes on the share of its net income that is allocated to foreign owners.

Second, investing directly from abroad will also subject the foreign company or investment fund to a "branch profits tax" in the United States that is collected in theory at the US border on any earnings that the foreign owner brings home, but that will be levied in practice without waiting for earnings to be repatriated.

Most countries collect two taxes on earnings: there is an income tax inside the country and a withholding tax at the border on dividends, interest and other payments across the border. The US withholding tax rate is 30%, but it is often reduced or waived entirely by bilateral tax treaties between the United States and other countries.

The United States started imposing a separate branch profits tax in 1986 on foreign companies that engage directly in business in the United States. Such companies escape US withholding taxes since earnings are repatriated to the head office merely by transferring them within the foreign corporation, not by paying a "dividend." The branch profits tax rate is the same as the withholding tax rate, but the main problems are that it is more difficult to control the timing and the tax is more complicated than the withholding tax to calculate. (US tax treaties that reduce withholding tax rates usually also reduce the branch profits tax rate, but it is important to check. Older tax treaties that were in effect before 1986 may prevent the US from collecting branch profits taxes.)

Branch profits taxes are collected on the "dividend equivalent amount," meaning the earnings and profits the foreign company had from US business operations / continued page 44

US Inbound Structures

continued from page 45

from which it could have paid a dividend. The amount is increased to the extent the foreign company had a lower net investment in the US business operation at the end of the year than when the year started. It is reduced to the extent the foreign company had a larger net investment in the US business operation at year end. The net investment is calculated by subtracting any debt related to the US business operation from the adjusted basis that the foreign company has in the assets used in that business. Unless significant capital additions are being made, the net equity will usually draw down as the existing assets depreciate.

Third, direct investment could also make it more expensive to exit the investment later.

The United States does not tax foreigners on their capital gains when US investments are sold, with one major exception. Congress became concerned in 1984 about growing Japanese investment in US farmland. The concern was that this would bid up prices and make it harder for smaller family farms to survive. It was too hard to define farmland, and so Congress ended up requiring that foreigners pay taxes on sales of interests in any "US real property." Part of a wind, solar, geothermal, biomass or other renewable energy project is considered real property. However, even if none of it were, the Internal Revenue Service has ruled that at least part of the gain a foreign company receives from sale of an interest in a US partnership is "effectively connected" income, meaning it is subject to net income taxes at a 35% rate. The foreign company will be taxed this way on the lesser of its gain or the share of gain the foreign company would have had to report as a partner if the partnership had sold all of its assets and liquidated.

One way to avoid a tax on exit is to hold the partnership interest or project through a US holding company that is treated as a corporation for tax purposes. Shares in the corporation can normally be sold without having to pay a US tax on the gain.

Care must be taken to avoid turning the US holding company into a "US real property holding corporation." It will be considered a holding company for real estate investments if at least half its total assets by market value are interests in US real property. Once the company becomes tainted with this label, then the taint will last for at least five years. Its assets are tested on numerous "testing dates."

The developer of a renewable energy project often signs an option to buy or lease a site as one of the first steps in the development process. In the case of a wind farm, he erects a meteorological tower and monitors the wind speed on the site for at least one to two years. Other early steps in the development process are to get in line to connect the project to the utility grid, obtain permits to build and negotiate a long-term contract to sell the electricity from the project to a nearby utility. It is important not to put the development assets under the holding company while 50% or more of the value is in the site. The US independent power industry takes the position that a site lease has value only to the extent the rents the developer is required to pay are below market. Its position is that a power contract has value only to the extent that the electricity prices are above market, so other contracts may not have much offsetting value beyond the cost to put them in place.

Delaware LLC

It is usually best to use a Delaware limited liability company as the US holding company.

Delaware has the most well developed body of corporate law among all the states, except possibly New York. Its limited liability company statute allows flexibility in terms of business arrangements among the owners. Most US lawyers at the larger US law firms are familiar with the Delaware statute; they are not as familiar with statutes in other states. This has sometimes led to situations where developers who have formed project companies in other states have had to reorganize them in Delaware before banks and tax equity investors will provide financing.

A limited liability company is like a corporation in that its owners are shielded from liability for the company's debts, but it has a lot more flexibility in terms of permissible business arrangements. It can function like a corporation with a board of directors, officers and periodic dividends to shareholders, or it can operate like a partnership where the members run the business directly and agree to changing ratios over time for distributing earnings.

Unlike a corporation, the owners can choose how they want a limited liability company to be taxed.

An election should usually be filed with the Internal Revenue Service within 75 days after the limited liability company is formed to treat it as a corporation for US tax purposes. The election is filed on Form 8832. The form is available on the IRS website at www.irs.gov.

The reason for filing within 75 days is that is the period that the election can relate back. The owners are free to change their minds later about the tax classification if the LLC has been a corporation from inception; otherwise, they are locked into the elected status for five years.

If no election is filed, then the LLC will be treated as a partnership for US tax purposes, if it has more than one owner, or as a "disregarded entity," if it has only one owner. A "disregarded entity" is ignored. It is treated for US tax purposes as if it does not exist.

Single Holding Company?

A separate holding company for each investment will allow more options when it comes time to exit a project. One project can be sold without having to sell others.

However, there is a tradeoff. Renewable energy projects in the United States usually do not start generating taxable income until three to four years after a project has started operating because of the large amounts of tax depreciation and tax credits to which the owner is entitled. The owner is better off using this tax shield himself if he has other income that can be sheltered with it rather than bartering it in the tax equity market where he will get less than full value for it. Using a single holding company for all projects will eventually create a tax base against which the tax shield can be used. A consolidated US income tax return cannot be filed for a series of separate US holding companies. Corporations can join in filing a consolidated return only if they are at least 80% owned by vote and value by a common US parent company.

It may be possible to get the benefits of consolidation while keeping separate US holding companies for each project by having whichever holding companies are earning taxable income enter into tax equity transactions with project companies that have just put new projects in service. These "cross chain" tax equity transactions raise a number of tax issues that require careful consideration and are beyond the scope of this article.

Other considerations may come into play.

For example, the foreign company may put employees on the ground in the United States. They may have responsibility for business operations not just in the United States, but also in Canada and Mexico or even into Central and South America. Depending on the nature of the business, it may make sense for administrative convenience to put all the western hemisphere operations under a single US holding company, but to make that holding company a disregarded Delaware limited liability company that sits atop separate subsidiary holding companies for each project in the United States and for business operations in each of the other countries. However, the US employees should stay in one of the subsidiary US holding companies. Making them employees of the disregarded umbrella holding company would cause the foreign parent company to have a "permanent establishment" in the United States. Since the umbrella company does not exist for US tax purposes, whatever it does is treated as done by its foreign parent company directly. Under US tax treaties, business profits of a foreign entity cannot be taxed in the United States unless attributable to a permanent establishment of the foreign entity in the US. A portion of the profits earned by the foreign parent could be attributed to the permanent establishment under US attribution rules.

Accumulating Assets

Care should be taken about the order in which assets accumulate under the US holding company for each project. Developers of US renewable energy projects usually secure an interest in a site for the project at an early stage the development process. At no point should 50% or more of the value be in assets that are considered interests in US real property.

The asset mix of the holding company will be tested on a series of "testing dates." The testing dates include the last day of each tax year of the holding company, and each day that an interest in US real property is acquired or sold. Once the holding company is tainted, the taint will last for at least five years. A tainted company is called a "US real property holding corporation."

Paying attention to the asset mix will make it more likely that the foreign company or investment fund can sell its interest in the project in the future without having to pay US taxes on its gain.

Any such sale would have to be of shares in the US holding company. As long as the holding company is not tainted, then no US tax will have to be paid on the gain.

If a tax is owed, then the gain will be treated as "effectively connected" income from a US trade or business, and will have to be reported by the seller by filing a US tax return. It will be subject to taxes not only at a 35% federal rate, but also to a branch profits tax. However, rather than take chances, US law requires the buyer to withhold 10% of the gross purchase price. The seller can get back any excess taxes it paid on its actual gain by filing a US tax return. */ continued page 48*

US Inbound Structures

continued from page 47

If the holding company is tainted by having owned too much US real property in the last five years, then it may be better to sell its assets and liquidate the holding company rather than sell shares in the holding company directly. The holding company will subject to US income taxes at a 35% rate on the asset sale, but there will usually not be any further withholding or branch profits tax to distribute the sales proceeds to the foreign owner.

Foreign investors with US projects should be careful about the order in which assets accumulate.

However, there is a risk of an "accumulated earnings tax." US corporations that accumulate significant earnings rather than pay dividends are exposed to a penalty tax at a 15% rate. The tax is imposed at the corporate level. The rate increases to 39.6% after 2012. The aim of the tax is to prevent corporations from waiting to pay dividends until a shareholder has losses that can be used as shelter or not paying dividends at all to enable individual US shareholders to convert them into capital gains at lower tax rates or foreign shareholders to avoid taxes altogether by eventually selling the corporate shares. The tax is infrequently imposed. It requires the IRS to substitute its business judgment for the judgment of corporate management by concluding that the corporation allowed earnings to accumulate beyond the reasonable needs of the business.

Another strategy to avoid a tax on exit is to sell shares in a foreign entity treated as a corporation for US tax purposes that owns shares in the US holding company. The US tax net does not reach such a sale.

While the strategy of using a separate US holding company for each project and electing to treat it as a corporation gives a foreign company a way to exit US projects directly without having to pay US tax on gain, the foreign owner may find it hard to arrange such an exit in practice. The exit requires selling shares in the US holding company rather than selling the interest it holds in the US project company.

Other things being equal, buyers prefer to buy assets.

One reason is fear of unknown liabilities in the corporate holding company, including the possibility that the holding company joined at some time in the past with other corporations in filing a consolidated return at the federal level or combined return at the state level. In such cases, the holding company may be subject to what US tax lawyers call "dash six" liability, or liability for unpaid taxes on the consolidated or combined return.

Another reason is anyone paying a premium over the current tax basis the project company has in its assets will want the premium to be reflected in a "step up" in the tax basis so that he can recover the premium through additional depreciation. The value of the step up tends to be higher in renewable energy projects than in other types of businesses because renewable energy assets are subject to faster depreciation allowances. There is usually no additional depreciation for the premium if corporate shares are purchased. This becomes a math exercise. The buyer will pay less because of inability to step up asset basis. The issue is whether the tax savings to the seller are worth the lower purchase price.

It is rare to see direct sales of project assets, because the assets usually include a power contract, interconnection queue position and permits that require consent from other parties to transfer. Most "asset" sales are sales of the project company or an interest in the project company.

Capitalization

Some time should be spent thinking about how to capitalize each US holding company, assuming part of the capital cost of the project will come from overseas rather than raising the entire cost locally.

The way to think about the question is to focus on the overall tax burden on the operating earnings from the project — not just in the United States, but also at the US border when earnings are repatriated and in the home country of the foreign company or investment fund. The US corporate income tax is 35%. There is a 30% withholding tax on dividends when earnings are repatriated. The withholding tax is often reduced under bilateral US tax treaties.

If the foreign investor injects part of its investment in the US holding company as a loan rather than injecting it entirely as equity, then the share of earnings pulled out as interest on the loan will attract a US withholding tax, but at least the interest will be deductible, reducing the income on which the 35% corporate tax has to be paid. This is called "earnings stripping." Some US tax treaties waive withholding taxes altogether on interest while reducing, but not eliminating, the rate on dividends.

One problem with trying to strip earnings is that capital-intensive businesses run losses. There may be no earnings to strip. The typical renewable energy project does not turn tax positive until sometime in the fourth year after the project goes into service. If the developer retains the US tax subsidies, rather than barters them in a tax equity transaction, then it can be as long as nine years before the project turns tax positive. Unused tax subsidies can be carried forward up to 20 years and used to shelter future income from the project from tax. Stripping earnings during a period when the US holding company is in a net loss position has the effect potentially to increase the overall tax burden. It may subject the earnings to a withholding tax earlier in time at the US border or in the foreign country, assuming the earnings are not exempted from taxes in the home country under a participation exemption or similar provision and the foreign country does not already tax them by looking through the US holding company under a controlled foreign corporation regime.

US rules also limit the extent to which the US will allow earnings stripping. The US will not allow part of the interest paid to a foreign parent company to be deducted if the debt-to-equity ratio of the US holding company exceeds 1.5 to 1 and the foreign parent company is in a country with a favorable US tax treaty that waives or reduces US withholding taxes on interest payments.

At worst, part of the interest paid to the foreign parent company each year cannot be deducted.

Calculating the share that cannot be deducted is complicated. There are two concepts: "disqualified interest" and "excess interest expense."

"Disqualified interest" is the interest that is paid to the foreign parent without US withholding tax. For example, if interest paid to the parent is subject to only a 5% withholding tax because of a favorable US tax treaty, then five sixths, or 83.3%, of the interest is considered disqualified.

"Excess interest expense" is the amount by which the net interest the US holding company pays during a year to all lenders exceeds 50% of its income before deducting interest, net operating losses, depreciation and depletion.

The amount of interest that will be disallowed in a year is whichever is less: the disqualified interest or the excess interest expense that year. For example, suppose the US holding company had income — after adding back any deductions it took for interest, net operating loss carrybacks and carryforwards, depreciation and depletion — of \$100 for the year, and the disqualified interest payments to its foreign parent were \$60, then \$10 of interest paid to the parent cannot be deducted. The \$10 can be carried to the next year and deducted then if there is room that year to deduct it under the 50% cap. The cap is cumulative. If interest paid to the foreign parent were only \$40 the first year, then not only would all the interest paid have been deductible but there would also have been \$10 of unused cap to carry forward to future years until used.

Debt borrowed from third parties is treated like a loan from the foreign parent company if repayment is guaranteed by the foreign parent company or an affiliate. In that case, the interest paid to the unrelated lender is disqualified interest to the extent there is no withholding tax on the payment to the unrelated lender. It does not matter that interest paid to the foreign parent would have attracted a full withholding tax. Whether there is a favorable tax treaty with the foreign parent company's home country is irrelevant.

When borrowing from third parties to raise capital for any equity the foreign parent must inject into the project, consider whether the debt should be in a location in the capital structure that allows the interest to be deducted by the foreign parent directly. The US holding company may not have enough tax base to deduct the interest in the US. The foreign parent might borrow directly and inject the funds as equity into the US holding company. This would give the parent an interest deduction at home. There are no earnings to strip in the US. Alternatively, the debt might be put in an entity one tier / *continued page 50*

US Inbound Structures

continued from page 49

up from the US holding company that is transparent for tax purposes in the home country of the foreign parent company, and the borrower would then inject the money as equity into the US holding company.

Until recently, it was more common to use an intermediate holding company in a jurisdiction with a favorable tax treaty with the United States to invest in US projects. An example might be a Dutch holding company. If the foreign investor is in a country without such a tax treaty, this was a way to qualify for a reduced withholding tax rate. However, recently-negotiated US treaties have limitation of benefits clauses that make such treaty shopping difficult. The foreign investor must have a meaningful business presence in the intermediate jurisdiction to be able to benefit from the treaty.

Finally, use of hybrid instruments and hybrid entities might also be considered.

An example of a hybrid instrument is a capital injection by a foreign parent into a US holding company that is viewed as a loan for US tax purposes but as an equity investment for tax purposes in the foreign parent company's home country. Suppose dividends are taxed less heavily than interest in home country X. Injecting capital under a hybrid instrument would allow earnings stripping in the US while allowing repatriated earnings to qualify for reduced taxes on dividends at home.

A hybrid entity is an entity that is viewed as transparent in one country but as a corporation in the other. These can offer benefits in some situations. An example is where taxes paid in the project country might be released for use as foreign tax credits at home or where interest deductions might pass through on borrowed money. There is probably more limited scope for use of such entities in the renewable energy sector because of the US tax profile of such projects than in other sectors.

How The Arab Spring Is Affecting The Project Finance Market In The Middle East

Portions of the Middle East remain in turmoil. Syria, Libya, Yemen, Egypt, Tunisia, Bahrain and Iraq are unsettled to varying degrees. A panel of experts talked in Paris in July about the extent to which the political instability has taken a toll on the willingness of developers and lenders to undertake new infrastructure projects in the region. The panelists are Philip Helmes, chief executive officer of Helmes & Co, a consultancy that is active in the region, Roland Kahalé, head of project finance (power sector) for the Middle East and Africa at BNP Paribas, and Peter Goodall, global head of natural resources at Crédit Agricole. The moderator is Sohail Barkatali with Chadbourne in Dubai.

MR. BARKATALI: What is different about the market today than seven or eight months ago?

MR. KAHALE: The market is differentiating among countries. Banks are returning to the fundamentals and analyzing what differentiates one country from another, which countries are weak and which are resilient to the crisis. This is a good thing for the long term.

It is harder to lend at the moment to support projects in Egypt, Tunisia, Bahrain and Syria and maybe to a degree in Jordan.

The fundamentals in many other countries in the region remain strong. Oil prices are still high and that is providing a boost to the economies of the Gulf Cooperation Council countries. The credit ratings of most of the GCC countries like Abu Dhabi, Qatar, Oman and Saudi Arabia did not change, while the credit ratings of the countries hit by the crisis were downgraded.

MR. GOODALL: I think it is worth remembering that in 2010, we were in a market that was recovering quickly from the crises of 2008 and 2009. If you had asked bankers what their principal concern was toward the end of 2010, they would have said regulation of liquidity ratios and where the market was going. Pricing was starting to move down because bankers were behaving like lemmings. Lemmings are very small, furry creatures that throw themselves off cliff edges without apparent reason. Banks will see a price going down and follow it in the same way.

The last thing they would have imagined is a sovereign risk in the Persian Gulf countries. It really was a shock to everyone to see that happen first in North Africa and then spread into the GCC. It has become a real issue today for credit committees at banks. There is a sense that people are backpedalling from doing business in a number of the countries.

Opportunities

MR. BARKATALI: Banks are picking and choosing their projects with more care and with greater attention to political risk within particular countries. Where do you see the best opportunities?

MR. GOODALL: Transactions that were conceived and launched in 2008 and 2009 take anywhere from three to five years to come through financing and construction completion. Three years ago, we were in the middle of a global financial crisis, so the project pipeline is slimmer and the opportunities are rather few and far between right now.

Clearly there are massive needs. For example, we hear about $88 billion that must be spent in Qatar in advance of the World Cup in 2022, including a port, an elevated railway and a bridge to Bahrain. There are still projects moving forward in the Emirates. Liquidity is somewhat tenuous. A number of banks have pulled out of the region. There are concerns over risk. However, the deal flow is not overwhelming, so deals are not being held up by a lack of liquidity.

MR. KAHALE: There should be a lot of opportunity in North Africa in the long run. Morocco is benefiting from the uncertain political climate in Egypt and Tunisia. We see a number of deals there, mainly in the conventional power and renewables sectors. There are perhaps four or five transactions that are likely to move ahead in parallel. In the GCC, opportunities remain in the proven markets like Abu Dhabi, Saudi Arabia and Oman. Qatar did not tender any new power projects in the last three years. Also, Dubai and Kuwait have both launched their first independent power projects, and the market is reacting positively.

MR. BARKATALI: Phil Helmes, what does the Arab spring mean from the standpoint of a project manager?

MR. HELMES: I work with a number of the sponsors and large engineering firms. A couple of my clients, including a big government contractor in the United States, are looking favorably at the region. The US contractor, who is very conservative, decided to switch strategy and embarked on a new strategy of stepping up its presence. It is setting up offices, moving people and trying to go after new infrastructure projects.

In Egypt, we submitted a proposal in 2008 for the first nuclear power plant. The contract was awarded in 2009. The project is continuing to move forward without any apparent impact. On the other hand, a private petrochemical project on the Suez peninsula in which we are involved is slowed considerably with only local and national bank participation, the risk profile worsened, and that project is limping along.

We just submitted a proposal two weeks ago for another project in Egypt. It appears that certain projects will move forward. Most of the ministries seem to be stable.

Right now the military is in control and things seem fairly stable. There is the potential after the elections for the situation to change. We think private sector projects are more likely to be affected by the election than public sector ones.

We competed recently for a technical advisory role in a large nuclear project in Abu Dhabi. The project seems to be moving along fine. We have clients who are actively pursuing work in Saudi Arabia, particularly in the power and the water sectors. They see Saudi Arabia as stable with plenty of opportunities.

Liquidity

MR. BARKATALI: Where is the financing coming from? Is there liquidity in the market? What is it going to take to finance these deals?

MR. GOODALL: It would be extremely difficult to raise bank financing for long-term projects in Egypt. Most people are waiting to see what happens in the elections. There is concern about the potential outcomes. Maybe I am being a little pessimistic, but that is our view of the situation at the present time.

MR. KAHALE: I agree. Elections are expected between now and the end of the year. There is uncertainty in the short term. Banks need to understand the path forward before they will lend on a long-term basis.

MR. BARKATALI: Moving away from Egypt, but staying with liquidity issues, how do you see the other Gulf countries? There are projects being tendered currently in Oman, Kuwait, Dubai and Saudi Arabia.

MR. KAHALE: There are not as many projects as we were seeing in 2007 in the power sector. A few deals are getting done in the main markets with proven models.

There is enough liquidity on a long-term basis to close these deals.

/ continued page 52

Arab Spring

continued from page 51

In Saudi Arabia, local liquidity supports a lot of these projects on a long-term basis on very aggressive terms.

In the other GCC countries, we see Korean and Japanese contractors are bringing financing from Japan and South Korean sources. The commercial tranches we see on these deals are not large, and there is enough liquidity on a long-term basis from the commercial banks to fill such gaps.

MR. GOODALL: The French banks are the most active banks in the project finance market according to the league tables. Overall volumes were down in the first quarter. It was a low point in terms of transactions. A huge portion of what got done was in Asia, particularly in India. French and Japanese banks remain active, and a number of other European banks are still playing along with a few American banks.

Political turmoil in the Middle East is creating financing challenges.

It is absolutely right to say there is enough liquidity for the pending deals, given the alternative sources of funding that are being used. We are seeing the export credit and multi-lateral lending agencies and local banks take more active roles. A contractor looking for a financing for something other than a mega-project will have to really rely on the local bank market or else take banks from its home country with it. The large project finance banks are not looking today at the smaller transactions.

MR. BARKATALI: So it is a case of look at what you can bring from home. There is commercial funding available. Export credit agencies are playing an active role. What about Islamic finance and the bond market?

MR. GOODALL: The project bond market has been seen as the next savior of project finance for as long as I can remember. The deal volumes have been very modest. There is a lot of talk at the moment, particularly in the Emirates, about using the bond market for refinancing: for example, for the refinancing of the Dolphin facility between Qatar and the Emirates and of Zayed University? One would think those long-term stable cash flows are the sort of thing that would attract bond investors, but it has not happened yet.

MR. KAHALE: We are seeing Islamic financing used mainly in Saudi Arabia as an alternative or complement to a commercial bank tranche. Most banks in Saudi Arabia can do either commercial lending or Islamic finance transactions.

In terms of the bond market, we are all waiting. Everyone is talking about the bond market, and for sure it is the latest trend. Abu Dhabi is probably the most advanced in looking at refinancing its existing projects in the bond market. There are some challenges to refinancing in the bond market in terms of breaking existing swaps and the economic value to sponsors.

Banks are still feeling their way about what must be done by 2019 to comply with the new capital ratios required by Basel III. The general direction is that there will be less long-term commercial bank financing. The bond market is important because it has the potential to substitute for the loss of liquidity as capital ratios tighten for commercial banks.

MR. HELMES: How large does a project have to be before it will be of interest to the commercial bank market? How large is too large for the current market?

MR. GOODALL: A project that costs less than $400 to $500 million is unlikely to be of interest to the project finance market. The banks are not underwriting projects today. Deals are being done as on a club basis.

MR. KAHALE: In 2007, there were probably 40 banks active in the project finance market. I remember an integrated water and power project in Saudi Arabia where we invited 32 banks and all 32 banks participated, with the result that we had to reduce their tickets. There was no issue in 2007 in project size. Today, some of these 40 banks merged or disappeared, and some have stopped project financing. There are probably a dozen active international banks in the project market in the Middle East.

Advice for Governments Tenders

MR. BARKATALI: What advice would you give to governments in the region about to tender new infrastructure projects? What can they do to ensure that the projects will be able to secure financing?

MR. KAHALE: I think today there is no need really to change the financing model that is currently in place. Deals are getting done on the basis of the existing model in places like Abu Dhabi and Saudi Arabia. Kuwait is following the proven model, and the feedback from the market has been very positive.

MR. GOODALL: Saudi Arabia is a good example of how things are working currently. There is massive liquidity in the local bank market. We have a bank affiliate ourselves in the Kingdom that has the capacity to lend very large tickets. The Saudi government has demonstrated a willingness to spend huge sums of money for rail and other basic infrastructure to support mining and petrochemicals projects. The government commitment to the downstream infrastructure is critical to luring the commercial banks to finance the upstream facilities.

MR. HELMES: Speaking from the perspective of a sponsor or construction contractor, these are massive projects. What we look for is a clear set of rules for the solicitation and a transparent process.

We put a large consortium together to bid on the Saudi land bridge. It started out fine. We spent a good deal of money. We followed the procedure, but we had concerns about how the project could be financed and still meet the objectives of Saudi Arabia. There was never any real dialogue with the bidders, and it drifted into a low bid situation. They wasted a year playing with the low bidder. In the end, the project could not be financed and the enthusiasm for the project waned and nobody wanted to do it over.

Compare that to our experience in Egypt. We put together a bid for a very sizeable project. The request for proposals was clear. The bidding had an odd start because 30 people showed up for the initial meeting. Everybody sat there. The chairman came out and said, "Welcome to Cairo. Do you have any questions?" That was the meeting. We all looked at each other. Somebody started to ask technical questions, but the meeting could not have lasted more than an hour. Despite the inauspicious start, the government followed the procurement rules to the letter. There was a public opening of bids. The deal went to the lowest bidder. The government sent letters to keep the other bids alive. The initial winner could not close. The deal went to the second bidder. It closed. The government let everybody know. We were disappointed we didn't win, but the process was transparent and fair.

MR. BARKATALI: How about other jurisdictions that recently tendered independent power projects: Kuwait and Dubai? Neither jurisdiction has a strong track record of using project financing for power deals. What will it take to do a deal in those countries?

MR. GOODALL: Banks have balance sheet constraints. Why do a project in Kuwait as opposed to a project elsewhere? It helps if there is the potential for a broader range of business for the bank than the one loan. Maybe the sponsor is a company that you work with in project finance, perhaps in capital markets, perhaps as a day-to-day banker in its home country. A relationship driver is important.

The risk allocation must also leave the bank with the same exposure that it would have been prepared to take before political unrest intervened in the region. That may mean bringing in multilaterals or export credit agencies to take political risk and maximizing borrowing from local banks through Islamic financing or some other form of liquidity.

MR. BARKATALI: Roland Kahalé, how would you finance a project in Dubai? Dubai's relationship with banks has been slightly estranged.

MR. KAHALE: Dubai's initial plan was to issue a project combining power and water, making it a very large project. Before issuing the RFP, they reduced the scope just to power, and I think that that was a very good initiative. The size of the project is manageable, and the timing is good because the EPC market today is much more favorable than it was. We still need to see how much support there will be for the project from government financing institutions.

MR. HELMES: Contractors do both power and wastewater, but through different divisions. It makes it easier on bidders to separate big projects by discipline. Many of the EPC contractors prefer that.

MR. GOODALL: We haven't really touched on pricing except to say that it stabilized and then came down toward the end of 2010 without getting anywhere near the levels we saw previously. There will be a premium to pay without a shadow of a doubt. And pricing will not return to pre-2008 levels any time soon because, in addition to the perception that there is greater political risk, you also have banks liquidity costs that are much higher than where they were previously.

MR. BARKATALI: Do the same considerations apply to the other jurisdictions? */ continued page 54*

Arab Spring

continued from page 53

MR. GOODALL: It is difficult to generalize. We mentioned Morocco as being a friendly environment where things could be done, but we do not have a massive history of project financing in Morocco. In Egypt, we are in a wait-and-see mode for at least a few months. Tunisia is "wait and see how things evolve."

Outlook

MR. BARKATALI: What is the future for projects in the Middle East?

MR. KAHALE: The fundamentals are there currently in the GCC countries to support project finance. Bahrain today is facing issues. North Africa has a strong potential, and I am optimistic for Egypt and Tunisia.

MR. HELMES: Contractors sense opportunity to earn fees for services, especially on government-related projects in Saudi Arabia. The nuclear power area is intriguing, with the nuclear power plants in Jordan, Abu Dhabi and Egypt. It will be interesting how these projects can be financed. With a nuclear power plant, you put in oodles of money without knowing whether the project will work until it is commissioned. The project can take 10 years to build. You are floating out there a long time with no cash flow from operations. I just don't know how you're going to finance that, but I see a lot of fee business.

MR. GOODALL: Our position at Crédit Agricole is that we have affirmed our desire to continue in the project finance market. Construction finance is one of the planks of development. We have a three-year plan that puts a lot of weight on the construction finance business. Beyond that, it will be a question of choosing among deals and getting the pricing right. I tend to think that there are a lot of issues that can be resolved through pricing for the banks. I am optimistic for the Middle East and North Africa. Let's not forget that the governments are cash rich. So as far as the contractors are concerned, the governments can get things done. They can write checks.

MR. BARKATALI: Phil Helmes, how do you see the EPC contractor market in the region developing and growing?

MR. HELMES: The region has money. There is less money in the US market. The number one rule for contractors is to follow the money. That is why one of our clients decided to drop some other strategic locations and focus on the Middle East. The EPC contractors do not have a lot of their own capital to put at risk. They need to team up with strong balance sheet sponsors like equipment manufacturers who can bring part of the financing in exchange for selling equipment. ◎

Oil and Fuel Companies Under Increasing Pressure to Stop Iran Business

by Ramsey Jurdi, in Dubai

The US government has ramped up its enforcement of economic sanctions on Iran by levying penalties on non-US companies.

In May, the government imposed penalties on Petróleos de Venezuela (PDVSA), Tanker Pacific Management (Singapore) and two entities within the Samy Ofer shipping organization for engaging in transactions related to refined petroleum with Iran. These companies have been barred from obtaining any significant US bank or Ex-Im bank financing and, in the case of PDVSA, from obtaining US government contracts.

These actions follow a recent flurry of activity by the US State Department to persuade non-US entities to stop doing business with Iran. To a large extent, the State Department has been successful, convincing the likes of LUKOIL, BP, Repsol, Lloyd's of London and Reliance to discontinue business with Iran. Further, Total, Statoil, Eni and Royal Dutch Shell have all formally committed to end their investments in the petroleum sector in Iran, under the threat of penalties by the United States. Sales of refined petroleum to Iran have decreased by 60% in the past year, according the State Department.

US efforts to curtail business with Iran since the strengthening of sanctions in the summer of 2010 are having a measurable effect. Notably, Iran Air, the national airline, is having difficulty refueling its planes in foreign airports, particularly in Europe. Prague and Budapest were reported in June 2011 to be the only remaining European airports that are willing to refuel Iran Air flights, which has prompted Iranian officials to threaten retaliation by prohibiting refueling of European carriers in Iran.

While US statutes have given the US government authority since 1996 to impose penalties on non-US entities for certain trade with Iran, the government has generally not exercised the authority. However, the US Congress tightened the sanctions in July 2010 through a new statute called the Comprehensive Iran Sanctions, Accountability, and Divestment Act, or CISADA, that expanded the activities subject to penalty, added to the available penalties, and removed much of the discretion previously afforded to the executive branch to impose or not to impose penalties.

Activities Subject to Penalty

After CISADA, the US government now has authority to penalize non-US companies that engage in three types of activities.

The first is investing in development of the Iranian petroleum industry. The second is selling goods, services or technology to Iran that help Iran produce refined petroleum products. The third is exporting to Iran refined petroleum products or facilitating someone else's exports of refined petroleum products to Iran. Before CISADA, only the first activity was subject to penalty.

The first penalized activity is making an investment that directly and significantly contributes to the enhancement of Iran's ability to develop its petroleum resources. The investment must exceed $20 million, either by itself or in combination with other investments, in a 12-month period. In March 2011, the US government imposed penalties on Belarusneft, a state-owned Belarusian energy company, based on a 2007 contract valued at $500 million for development of an oil field in Iran. The increasing risk of penalties appears to have caused Total, Statoil, Eni and Royal Dutch Shell to commit formally to end their investments in the Iranian petroleum industry.

The United States is penalizing non-US companies doing business with Iran.

Construction, oil field services and shipping companies are most at risk of violating the ban on selling goods and services that help Iranian refineries. The sanctions target sales of $1 million or more for a single transaction and multiple transactions exceeding $5 million in the aggregate during a 12-month period.

The new ban on sales of refined petroleum to Iran is having the most noticeable effect in the petroleum industry because of its applicability to a range of both up-stream and downstream market participants. The ban applies both to exports of refined petroleum products to Iran and to sales, leases and other provisions of goods, services, technology, information or support to Iran that enhances its ability to import refined petroleum products. An activity must reach $1 million for a single transaction or $5 million for multiple transactions in a 12-month period to be covered by the ban.

Recent penalties and announcements by the US government show the broad reach of this provision.

PDVSA was penalized for exporting reformate, a midstream blending component that improves the quality of gasoline, to Iran. The US State Department said the company delivered at least two cargoes of reformate between December 2010 and March 2011 valued at approximately $50 million.

Tanker Pacific Management was penalized for leasing a tanker to a front company for the Islamic Republic of Iran Shipping Lines (IRISL), and two Samy Ofer group entities were penalized for brokering the same tanker transaction, both considered to be a provision of goods or services that enhances Iran's ability to import refined petroleum products. Interestingly in this case, the US government said the three companies failed to exercise due diligence and did not heed publicly available and easily obtainable information that would have indicated that they were dealing with an IRISL front company.

Swiss energy traders Vitol, Glencore and Trafigura have announced they plan to cease transactions with Iran, and airport fuel companies in many countries are refusing to refuel Iran Air flights. */ continued page 56*

Iran Sanctions

continued from page 55

Potential Penalties

The US government can choose from a list of nine penalties when penalizing a non-US entity. It must impose at least three of these penalties; only two penalties were required before CISADA was enacted last summer. The penalties can be broadly described as denying the non-US entity the benefits and privileges of doing business with the United States.

The nine possible penalties are 1) denial of assistance from the US Export-Import Bank, 2) denial of export licenses, 3) a bar against US financial institutions lending more than $10 million in a year to the company, 4) a ban on any financial institution that violates the sanctions from acting as a primary dealer or repository of government funds, 5) debarment from US government contracting, 6) a prohibition on certain foreign exchange transactions, 7) a denial of banking services from US institutions, 8) a freezing of property in the United States and 9) a prohibition on making export sales in the United States.

The penalties against PDVSA for exporting two cargoes of reformate to Iran were a ban on US financial institutions making more than $10 million in loans to the company, disqualification from US Export-Import Bank assistance and denial of export licenses. These actions are expected to increase financing costs for PDVSA and prevent it from selling to the US Strategic Petroleum Reserve, which it has done in the past. However, the US government made clear that the penalties will have no effect on PDVSA's ability to export crude oil to the United States and will not apply to PDVSA's US subsidiary, CITGO.

The potential for the US government to target affiliates of an entity transacting business with Iran is a significant risk. CISADA allows the government to penalize the parent company, subsidiaries and sister companies of an entity transacting business with Iran. While the statute requires that the affiliated company have knowledge of the transaction and, in some cases depending on the relationship between the entities, to have participated in it, penalties are hard to fight once imposed and so it is best to assume that affiliated companies will be caught in the same net as the company violating the sanctions.

Discretion and Diplomatic Efforts

CISADA removed most of the discretion for the government to impose penalties when it finds sanctions violations. Even though the US had the option of penalizing non-US companies doing certain business with Iran since 1996, no penalties had been imposed before September 2010.

One circumstance where penalties can be waived is if the President certifies to Congress that the target company is no longer engaged in the sanctioned activity or is taking verifiable steps toward stopping the sanctioned activity. The President invoked this provision with respect to Total, Statoil, Eni and Royal Dutch Shell.

The US Government is also using diplomacy to head off the need to impose penalties. Diplomatic efforts led jet fuel suppliers in 17 cities in Europe and Asia to stop supplying fuel to Iran Air. Fuel suppliers will be subject to penalties if they sell more than $1 million in fuel in a single transaction or make multiple sales exceeding $5 million within a 12-month period. The value of the fuel is assessed based on the fair market value. The government is expected to take an aggressive approach to determining which threshold applies, such as treating a single requirements contract for periodic fueling as a single transaction, subject to the $1 million threshold instead of the $5 million threshold.

Sales of fuel to Iran Air are prohibited because Iran Air is an instrumentality of the Government of Iran, a requirement under CISADA. Sales of aviation fuel to private Iranian carriers would not be per se subject to penalty under CISADA. However, the US government is looking into the possibility of private carriers taking on more fuel than needed in foreign airports and whether the excess fuel is an export subject to penalty.

The US government continues to draw a strong connection between revenue generated from the Iranian energy sector and funding for development of nuclear and missile programs in Iran.

According to the State Department, the drop in sales of refined petroleum is forcing Iran to convert its up-stream petrochemical plants into gasoline refineries, leading to the loss of millions of dollars in export revenue. In view of this, penalties against non-US entities doing business with Iran can be expected to increase. ◎

Battle Over Power Contracts

Google signed long-term contracts with NextEra Energy to buy electricity from wind farms in Oklahoma and Iowa. It cannot use the electricity directly legally so it resells the electricity into the wholesale market, making the arrangement a form of hedge. The company is a large electricity consumer in both states because of its computer servers. Does this suggest another avenue for project developers? California is moving to allow utilities to halt electricity purchases during periods when contracted prices are above the current market price for electricity. How will California projects get financed? Why are utilities insisting that they have to treat long-term power contracts as leases of the power plants selling them the electricity? Does it matter, and can developers do anything about it?

A panel discussed these subjects at the annual Chadbourne global energy and finance conference in June. The panelists are Ken Davies, program manager at the time of Google Energy, Bob Shapiro, a partner in the Chadbourne Washington office, Bill Monsen, a principal with California-based consultancy MRW & Associates, Inc., and David Wittenburg, a director with Deloitte in Dallas. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We have three focuses of this panel, one of which is some very interesting news about two contracts that Google signed with NextEra Energy to buy electricity from wind farms that NextEra is planning to build in Iowa and Nebraska. Ken Davies, how long will the contracts run?

Google Contracts

MR. DAVIES: Both are 20-year contracts. We see value in getting a long-term embedded hedge. We want to lock in the current electricity price for 20 years. We are making capital investment decisions on the order of 15 to 20 years. We would like to lock in our costs over the same period. Electricity is our number one operating expense after head count.

MR. MARTIN: Can you say what the price per megawatt hour is in the two contracts?

MR. DAVIES: Unfortunately, I can't, but it is discoverable through our public filings.

MR. MARTIN: So there is a website where we can get this information by doing a Google search?

MR. DAVIES: You can even use Bing. [Laughter]

MR. MARTIN: You have very large servers in Iowa and Nebraska that use a lot of electricity, but you are not able to use the electricity you are buying by law because retail sales are not allowed in those two states, so you have to resell the electricity. How exactly do these contracts work as hedges for you?

MR. DAVIES: We are buying at the bus bar at a fixed or sometimes escalated price and then selling into MISO and soon to be SPP, respectively. We are getting exposure to the spot price, and we see that as a hedge to the price that we are paying at our data centers.

MR. SHAPIRO: You are selling at a wholesale spot rate and buying back at a retail rate?

MR. DAVIES: Yes. We are being charged a retail rate for what we actually consume, but we are often able as a large energy consumer to negotiate for a much lower retail rate than is paid by the average consumer. In many cases, what we are paying for the retail power is lower than what we are paying for the renewable electricity even today in a soft market. We are signing contracts with three to five years of fixed pricing, but over the life of the data center, those will reset. We are short-term fixed and long-term floating, so it will not be a perfect hedge in the near term. We are less concerned about hedging our cash flows on a quarter by quarter basis. We are more concerned about the long term.

MR. MARTIN: Both contracts are expected to cause Google to lose money on buying and reselling, at least in the short term, but you expect them to turn around over time and turn a profit over the entire contract term of 20 years. How do you protect yourself against the contracts ending early so you get the full benefit of your bargain?

MR. DAVIES: That is one of the things that we were very concerned about during negotiations. It is also one reason why we teamed up, at least for these first two, with NextEra, an experienced developer.

Most offtakers committing to buy electricity under long-term contracts will be concerned about what happens if the developer fails to finish the project or runs into difficulties after the project is already operating. Utilities are better equipped to step in and take over if the developer fails. We do not want to be in that position.

We are frankly less concerned about whether the project is built and operates during the early years. If the project falls behind schedule and we receive no power for the first five years, that might actually be okay with us. / continued page 58

Power Contracts

continued from page 57

We are losing considerable amounts of money on every megawatt hour. We just want to ensure the project is there in the later years. We pay a lot of attention to counterparty risk and the credit support.

MR. MARTIN: Do the contracts have a notional account to track how far behind you are and how much ground you have to make up. Does NextEra guarantee payment of whatever the remaining balance is in the account if the contract ends early?

MR. DAVIES: If the contract were to end early, then there are obviously penalties. In terms of volumes, we stay completely away from any sort of notional volume. I see some on the panel nodding, and I think they understand that this is so we can avoid the need to mark the positions to market.

MR. SHAPIRO: I read that you are retiring the renewable energy credits or RECs rather than trying to get value for them. Why do that?

MR. DAVIES: We purchase carbon credits. We have been doing so since 2007, and Google is a carbon-neutral company. We would like to move away from carbon credits because they are a pure tax on us. So we have a shadow price of carbon. Every REC that we retire means we can buy fewer carbon credits on the spot market.

MR. SHAPIRO: So it is part of being a good corporate citizen in the environmental area.

MR. DAVIES: Yes.

MR. MARTIN: Since you expect the contracts to turn around but you are losing money at the start, what are wholesale electricity prices today in the two states and how much do you expect them to increase over time?

MR. DAVIES: In MISO and SPP, wholesale prices are currently around $25 to $30 a megawatt hour. In some places, it is almost as if coal is still on the margin. These are very low prices, but we expect them to increase. When we started this a year and a half ago, we had a carbon assumption baked into our forward price curves. We no longer have that. But even removing the carbon tax, we still think the contracts will be profitable in the long term.

MR. MARTIN: The bank and tax equity markets are not keen merchant plants, and yet Google seems to be taking that risk.

MR. DAVIES: For us, it is a form of support for renewable energy. We have the ability to do what very few other people are willing to do in the market.

Project developers can learn from contracts that Google signed to buy electricity from two wind farms.

MR. MARTIN: How much capacity does Google have to enter into similar arrangements with other developers? I think you told me earlier you are prepared to enter into similar contracts in five or six states.

MR. DAVIES: We are not allowed to disclose our actual footprint. That said, it is public knowledge that we have data centers in the Carolinas, Iowa, Oklahoma and Oregon. So that is five. We have done two contracts, and I think everyone can do the math and figure out how many more we might be likely to do in the US as an initial matter.

MR. MARTIN: You said it was important to have an experience developer as the counterparty. How important is it to have a developer with a large balance sheet?

MR. DAVIES: Very important. We would like to be able to support smaller developers, but we worry about their staying power over 20 years.

MR. MARTIN: So you will take merchant risk but not credit risk. Would you consider contracts with other energy sources — for example, solar, biomass, geothermal, fuel cells?

MR. DAVIES: Absolutely. We have both fuel cells and solar panels on our campus in Mountain View. The problem is that they are competing here against high PG&E retail rates while in Iowa and Oklahoma, they would be competing against industrial rates in cold states. They may make sense here. It might be a little longer before they make sense for our data centers in other locations.

MR. MARTIN: Google will only do agree to long-term contracts in states with an active spot market, correct?

MR. DAVIES: Right now, yes.

MR. SHAPIRO: Did you explore trying to make direct sales to your buildings by having a utility wheel the power to them?

MR. DAVIES: We are always in conversation with our utilities, and that is one of the subjects we have explored. The utility model is still to apply a large retail markup in most cases. As for wheeling, it is a little more than we want to take on.

MR. MARTIN: Ken Davies, thank you for joining us.

MR. DAVIES: It was a pleasure. If you want to know more, I encourage you on our www.google.com/green website, we have a full-length paper explaining what we are doing and the full rationale behind it.

California Curtailment

MR. MARTIN: Bill Monsen, you wrote in the *Project Finance NewsWire* in June about changes in market rules in California. The changes were approved by the California Public Utilities Commission and affect the forms of power contracts that utilities use with independent generators. You said these changes will have two effects. One is that renewable energy projects will be more likely to find their projects curtailed or knocked off the grid during periods when market prices for electricity are below what the utility promised to pay in the long-term power contract. In what circumstances will utilities have a right to cut somebody off like this?

MR. MONSEN: These are new rules. The contracts that will allow this curtailment are just being bid for in utility requests for proposals.

MR. MARTIN: So this form of economic curtailment is a risk only in new contracts. It does not affect any existing contracts?

MR. MONSEN: One California utility, Southern California Edison, contends that it has a right under its existing contracts to curtail projects when the contract price for electricity exceeds that it can pay in the spot market. The California Public Utilities Commission pretty much said, "We are not going to get in the middle of a contract interpretation issue. There are dispute resolution mechanisms in the contracts. If Edison does something that a counterparty does not like, then the parties can settle through those mechanisms."

MR. MARTIN: That sounds like it will land eventually in court.

MR. SHAPIRO: Edison has been known for pushing the envelope. It is the biggest game in town. Its contracts have a provision that most people interpret as permitting operational curtailment and not economic curtailment. Edison then changed its form of contract to make its position more explicit. It basically said to the commission, "Oh, by the way, we have same right in our existing contracts." This has put some stress on financing projects. The better view is existing contracts are not affected.

MR. MARTIN: In what circumstances can a project be cut off under the new form of agreement?

MR. MONSEN: Under the new rule, or the new proposed contracts, the utility will have the ability to curtail a project for economic reasons for up to a fixed number of hours.

MR. MARTIN: Per month? Per year? Per day?

MR. MONSEN: It is per year. However, the utilities are asking in their solicitations for generators to provide pricing for different levels of curtailment. They want generators bidding to supply electricity to indicate in their bids how many hours of curtailment they are prepared to accept, whether they require compensation for production tax credits during periods when the project is curtailed, and whether there is curtailment in both on- and off-peak periods.

At the end of the day, the utilities will want to curtail when the CAISO price for electricity is significantly less than the contract price.

One of the drivers behind the utilities wanting the right to curtail is the independent system operator is proposing to reduce the floor price for electricity from negative $30 to negative $300 per megawatt hour.

MR. MARTIN: What does it mean to have a negative price?

MR. MONSEN: It means the generator must pay to deliver electricity.

MR. MARTIN: Is there a cap on the quantity of electricity that can be curtailed?

MR. MONSEN: There is no cap on quantity under the solicitations. It is a cap on hours. The Public Utilities Commission said about 5% would be a reasonable number, but the utilities, other than San Diego Gas & Electric, went in another direction. They are asking generators how much the utilities have to pay to the generator to retain a right to curtail for up to X number of hours. For example, what is it for 50 hours? What is it for more than that?

MR. WITTENBURG: The generator will have the option to sell directly to the grid as opposed to a utility if the pricing is advantageous, correct?

MR. MONSEN: A generator could try to do that, but I don't think its contract with the utility will allow it.

/ *continued page 60*

Power Contracts

continued from page 59

MR. WITTENBURG: I was being fascetious. It seems like a one-sided cap.

MR. MARTIN: Bill Monsen, what is the status of this rule? Is it final?

MR. MONSEN: Yes. The Public Utilities Commission issued a decision in April, and there have not been any applications for a rehearing. As a result, it is moving forward.

MR. MARTIN: So every new power contract signed in California will be subject to economic curtailment?

MR. MONSEN: Potentially. It is a form contract, and generators can try to negotiate away those curtailment rights, but I do not see the utilities willing to give much ground.

MR MARTIN: Is there any difference between how out-of-state generators and in-state generators will be treated?

MR. MONSEN: The out-of-state generator is covered if it has either a direct connection into the California ISO or does something called dynamic scheduling that makes it effectively a generator within the ISO system. An out-of-state generator who is selling electricity that is ultimately shaped and firmed would probably not be covered.

MR. MARTIN: Let's move to the other effect of this rule change. The other effect is to expose renewable energy projects to potential penalties if they deliver more or less energy than is scheduled for a particular hour. How do the penalties work?

MR. MONSEN: It is not literally a penalty. The rule basically treats renewable generators more like traditional generators. If a renewable generator delivers more electricity than it was scheduled to deliver in a particular hour, then it is paid a different price per megawatt hour. If it delivers less than scheduled, then it has to compensate the ISO.

MR. MARTIN: It makes the revenues from a project less predictable.

MR. MONSEN: That is exactly right.

MR. MARTIN: What is the potential swing in revenue for a typical project?

MR. MONSEN: The California ISO did some analysis. It concluded that if the rules had been in effect in 2009 to 2010, the swing would have been around $1.30 a megawatt hour. It is a small number. The swing would have been larger before 2009 because forecasting tools were not as good then. Generators can predict more accurately today what they are likely to deliver for purposes of scheduling.

MR. MARTIN: Wind projects are probably at greatest risk because it can be difficult to predict wind speeds. Do you know how much of a swing there is within an hour at a typical wind farm between what was forecast and what was delivered?

MR. MONSEN: It obviously varies by location, but a general rule of thumb might be between 3% and 5%.

MR. MARTIN: I was thinking that these penalties would push more wind farms and perhaps solar projects to install large storage devices, but the swings you are suggesting may not be large enough.

MR. MONSEN: That is exactly right. The cost of storage is still too large in relation to the potential hit to revenue. However, views could change over time if we see significant amounts of curtailment as has happened in the Pacific Northwest this summer.

MR. MARTIN: What caused the curtailments in the Pacific Northwest?

MR. MONSEN: It has been an amazing hydro year in the Pacific Northwest, and electricity prices are in the toilet.

MR. MARTIN: Bob Shapiro, given what you have heard, what would you advise developers about their ability to finance California projects?

MR. SHAPIRO: The bottom line for lenders has always been that they can finance something if they can quantify the risk. To the extent that negotiated contracts have a maximum number of curtailment hours, lenders can evaluate that. They will probably use the maximum number as the base case, but the project should be financeable.

Of course, the higher the number of allowable curtailment hours, the smaller the amount of debt that a developer will be able to borrow to finance his project.

The big issue that Edison had when talking about existing contracts is "negative avoidance costs" - having to pay money to get rid of electricity. Edison made noises about trying to come up with a global settlement with existing projects. Its offer was that there would be no economic curtailment as long as the ISO spot price is a positive number. I don't know whether it got many takers for existing contracts, but that may be a way to limit the curtailment risk. A generator could get an outside consultant to analyze how much risk there is of negative avoidance costs based on the project location.

MR. MARTIN: It sounds like the CPUC was wise to stay out of the middle of the dispute between Edison and generators. It sounds like abrogation of an existing contract for Edison to say, after the fact, "By the way, we can cut you off if we don't like the price."

MR. SHAPIRO: It is only wise if it does not affect the ability of projects to go forward. I think so far it has not, but the commission has never hesitated to intervene when needed, so although its current public position is it does not want to get involved, if there is a hiccough, the commission might reconsider.

Power Contracts as Leases

MR. MARTIN: Let's move to David Wittenburg from Deloitte. Utilities sometimes insist that they must treat power contracts with independent generators as leases of the underlying power plant for book purposes. Are the utilities correct, and what difference does it make?

MR. WITTENBURG: A PPA could take a number of different forms. The utility might prefer to treat the arrangement as a lease of the power plant in order to add its spending to rate base so that it can earn a return.

MR. MARTIN: So a utility might prefer to treat the arrangement as a lease. Doesn't that then require the utility to show the obligation to pay ongoing rent as a debt on its balance sheet?

MR. WITTENBURG: Yes, if it is a capital lease. If the utility can structure the arrangement so that it is an operating lease, then the obligation to pay future rents does not show up on the balance sheet.

MR. MARTIN: An operating lease is what you have when you walk up to a Hertz counter at the airport and rent a car, and a capital lease is closer to borrowing money?

MR. WITTENBURG: The current state of the lease accounting rules is form driven and an operating lease and a capital lease are not terribly different in terms of how they are structured. But in terms of describing it, you got it right. Operating leases are currently off balance sheet, but there is a 99% chance that will change in the near term. Capital leases are on balance sheet, similar to debt.

MR. MARTIN: Is it possible today for a utility to have the best of both worlds by treating the arrangement as an operating lease, but also have a rate-based investment? Is that possible, or does one need a capital lease to have a rate-based investment?

MR. WITTENBURG: It depends on what the state regulatory framework where the utility is located, but we have seen a number of utilities take the position that power contracts are operating leases.

MR. MARTIN: What must be true of the power contract before a utility can legitimately say that it is leasing the power plant?

MR. WITTENBURG: Under the current rules, but without getting into all the technical detail, the power contract is a lease if the utility has a right to use the asset, either via hiring and firing decisions, making operating decisions or because of the pricing in the contract itself. I emphasize "current" rules because the Financial Accounting Standards Board is in the process of rewriting them.

MR. MARTIN: What do you mean by "the pricing in the contract itself"?

MR. WITTENBURG: The contract is more likely to be classified as a derivative or power contract, rather than a lease, if electricity is priced in a way that does not transfer any risks or rewards of owning or operating the facility to the utility.

MR. MARTIN: If the power contract has a capacity payment as well as an energy payment, is it more likely to be viewed as a lease? If it has only an energy payment, is it less likely to be a lease? Does it matter whether the utility has an option to purchase when the contract ends?

MR. WITTENBURG: Not necessarily. A purchase option could affect the accounting in other ways. For example, it could require the utility to have to consolidate the project company on its books. The consolidation rules under US GAPP are very complicated.

MR. MARTIN: Power contracts for wind and solar projects usually require the utility to pay only for energy and not also for capacity. When would a utility entering into such a contract take the position that it is leasing the wind or solar facility?

MR. WITTENBURG: When it has effectively a right to use the facility. It would probably take that position if another entity does not have a right to use a significant amount of output from the facility. It is more likely to be viewed as a lease if there is a capacity payment.

MR. MARTIN: So the key is whether the project is effectively dedicated to the utility. Does the term of the power contract matter? For example, what if the facility is expected to last 35 years, but the power contract is only for 10 years?

MR. WITTENBURG: A 10-year contract is more likely to be an energy contract than a lease.

MR. MARTIN: What difference does it make to the independent generator whether the contract is characterized as a lease or a power contract?

MR. WITTENBURG: The independent generator may also want the contract to be a lease. It may / continued page 62

Power Contracts

continued from page 62

want to get the contract off its balance sheet. A contract that is not a lease is usually classified as a derivative, which would require marking the value to market at the end of each year. That can lead to volatility in earnings. For this reason, a generator may try to structure the contract so that it is considered an operating lease of the power plant. It will lead to more predictable earnings.

MR. MARTIN: So a generator may prefer to have a lease. Is there any circumstance where a generator would prefer to have the arrangement treated as a power contract?

MR. WITTENBURG: Yes, if the generator is trying to match costs. Let's say the form of fuel contract the generator has requires it to mark the fuel contract to market each year. It might be better in that case also to mark the power contract to market.

MR. MARTIN: You mentioned two other horrors. One is that the contract could be characterized as a derivative. What are the consequences for the generator and for the utility if the contract is treated as a derivative?

MR. WITTENBURG: There are three possible outcomes in terms of accounting for the contract in that case. First, the default accounting is the contract must be marked to market.

MR. MARTIN: Every year the generator must mark the contract to market, meaning record on its books the current value of the contract, and that affects the generator's earnings.

MR. WITTENBURG: As an example, suppose your contract price was $50 when you executed it. That was the market price for electricity. Forward market prices go up to $80. That leads to a $30 addition to earnings. What goes up can also come down. You can imagine the potential volatility over the term of the contract.

MR. MARTIN: Nobody likes that except, as you said, in the case where the fuel contract is also being marked to market.

MR. WITTENBURG: Yes, so that it gives some level of balancing the account, although the balancing is not perfect.

MR. MARTIN: And a utility? Does it care whether the contract is a derivative?

MR. WITTENBURG: The utility normally gets to pass through all of its costs to its ratepayers, so it does not care as much, except there is an administrative burden in terms of having to mark the contract to market, particularly if it is a 20-year contract.

New curtailment policies in California could drive wind and solar developers in the state to install large storage devices.

MR. MARTIN: So the utility would also have to mark to market?

MR. WITTENBURG: Yes, if the contract is classified as a derivative. Let me take a step back. If the contract is a derivative, there are three possible outcomes. The first is that the contract must be marked to market. The second is that you can call it a hedge and get special accounting if you meet certain requirements. The third, if you are talking about a physical contract as opposed to a financial contract, is that you can scope it out altogether and the utility can call it a normal purchase of electricity or the generator can call it a normal sale of electricity if certain requirements are met.

MR. MARTIN: Scope it out meaning ignore all the stuff we just talked about?

MR. WITTENBURG: Ignore all of that and not have to mark the contract to market.

MR. MARTIN: That seems like the best approach for both parties.

MR. WITTENBURG: A lot of companies try to do that. The only problem is that it is an election. It is not an automatic scope out. You have to maintain the facts that made the election possible. The utility must demonstrate that it is not reselling the electricity other than to its own ratepayers. A utility can probably demonstrate that unless it is contracting for amounts beyond its projected load requirements.

MR. MARTIN: All of these rules are about to change because the US is moving to international accounting standards. When is that change expected?

MR. WITTENBURG: That is the million dollar question for the accounting industry. The US Securities and Exchange Commission issued another white paper last month in which it said it supports movement toward international standards, but not full-blown conversion, but it did not give a date. That said, there are a number of projects underway, many of which will probably become standards this year, including for leases, financial instruments and revenue recognition.

The approach the SEC is taking has been called "condorsement." It hasn't fully endorsed the international accounting standards, but is in favor of convergence. The commission has not said that all SEC registrants must adopt IFRS by a certain date. It said it is still studying the subject and supports meshing US GAAP with IFRS.

MR. MARTIN: The direction in which this is moving on convergence is what? There will no longer be a distinction between operating leases and capital leases? Everything will be a capital lease?

MR. WITTENBURG: Not necessarily. A capital lease will remain as before. If the arrangement is a capital lease, then the lessee will have to put the asset on its books, and it will treat the obligation to pay future rent as a form of debt, just as if it owned the asset. The operating lease model that is currently proposed will put the right to use the asset on the books, not necessarily the asset itself. The right to use the asset would be recorded on the lessee's books at its present value as an asset, and the present value of the expected future rents would be recorded as an offsetting liability. The tricky part is what happens if there is a renewal option. It will not be as simple for the lessee as determining what its obligation is and putting it on the balance sheet and then forgetting about it. The lessee will have continually to evaluate whether it is more likely than not to renew and adjust the present value of the lease obligation accordingly.

MR. MARTIN: So there will still be distinctions among derivatives, different types of leases, energy contracts, all these things will still be relevant under the international standards, but the tests may be a little different.

MR. WITTENBURG: Yes. As you can imagine, most of the companies in this space today have thousands, maybe tens of thousands, of operating leases depending on a company's size, and we are not talking about just PPAs. The exercise of evaluating everything once the standards change will lead to a lot of heartburn.

MR. MARTIN: This is a boost for the accounting industry. You have the Sarbanes Oxley Act and now this. It seems like this could double the big four firms in size just to handle the workload.

MR. WITTENBURG: Not only is it going to present a lot of opportunities for the accounting firms to assist, but it will also be a monumental task for companies to get their arms around the effects. They are broad reaching. Putting all of these leases on balance sheets may affect debt ratios and covenants in existing financings. Companies need to start focusing on the potential effects now. ◎

Practical Advice: Wind and Solar Projects on BLM Lands

by Scott Bank, in New York

At the start of the 20th century, individuals and companies could explore, develop and purchase US federal lands containing natural resources with relative ease. Under the General Mining Law of 1872, such resources were transferred to full private ownership for fairly nominal sums through a process known as "patenting."

Eventually, Congress decided that natural resources on federal lands should remain under federal ownership. The Mineral Lands Leasing Act of 1920 signaled a policy shift in this regard. It was the first step toward what has become a complicated series of interrelated statutes and agency regulations that govern leasing and permitting for energy exploration and production on federal lands. These statutes and regulations now ensure that oil, gas and other natural resources found on federal lands remain under federal ownership or control.

One such statute, the Federal Land Policy and Management Act of 1976, empowers the Bureau of Land Management or "BLM," an agency within the US Department of the Interior, to grant federal rights-of-way to qualified applicants who want to build wind and solar projects.

BLM administers approximately 253 million acres, or one eighth of the US land mass. BLM also manages 700 million acres of subsurface mineral rights underneath federal, state and private lands. / continued page 64

BLM Leases

continued from page 63

Most BLM lands are not available for use by independent power companies. Lands designated as wilderness areas, national monuments, national conservation areas (with the notable exception of the California Desert Conservation Area), national wild and scenic rivers and national historic and scenic trails are all specifically closed to private development. However, vast swaths of BLM-administered land have been identified as having significant solar (22 million acres in six states) or wind (20.6 million acres in 11 states) potential. As of March 2011, BLM had approved nine solar projects with a total generating capacity of more than 3,600 megawatts and one 150-megawatt wind project. There are an additional 10 solar and five wind project applications, representing about 4,149 total megawatts, which BLM has designated for "priority" review status.

All of this activity — approved and pending — has required billions of dollars in loans and loan commitments. Lenders review BLM rights-of-way in the same way they review leases, easements, licenses and other real estate rights for projects on private lands. Chadbourne has represented lenders, developers and equity participants in numerous BLM solar, wind and geothermal projects, and we have not had a transaction fail due to issues tied to BLM.

The rights-of-way granted by BLM for solar and wind projects differ from privately-granted real estate interests in several important respects. The lender concerns in this area generally fall into four categories.

Retained Rights

Perhaps the most significant difference between BLM rights-of-way and rights over private lands is the level of control BLM retains over the land it administers.

A private lessor or easement grantor generally retains very few rights.

BLM retains significant rights, including a right of continuing access, a right of common use of the subsurface and air space, authority for others to use the right-of-way for compatible uses, retention of mineral rights, the right to decide later whether the grant is renewable, and the right to change the terms and conditions of the right-of-way to conform to any changes in legislation or regulation or as otherwise necessary to protect public health or safety or the environment.

Estoppels and Consents

BLM will not, as a general rule, involve itself in the details of a developer's financing transaction.

As such, unlike private landowners, BLM will not give typical estoppel certifications in favor of a lender. Rather, BLM will generally only acknowledge that the lender is taking a security interest in a right-of-way and, after reviewing the file pertaining to the right-of-way, state that the right-of-way is in good standing because rent payments are current or because BLM is unaware of any defaults by the holder of the right-of-way.

BLM allows lenders to record their mortgages or deeds of trust and to have those security interests reflected in the BLM's serial register.

However, BLM will not give a typical consent to collateral assignment (where foreclosure results in automatic assignment to the lender). Instead, BLM will require the lender, upon foreclosure, to apply to BLM for an assignment of the existing right-of-way or for a new right-of-way.

Mining Claims

With their potential to disrupt surface operations, mining claims are inimical to wind and solar projects (particularly solar). Unfortunately, mining claims that are filed or "located" prior to a final right-of-way grant are difficult obstacles to clear in the context of financing a solar or wind project.

Under the General Mining Law of 1872, a BLM right-of-way cannot endanger or interfere with a properly-located mining claim. Thus, mining claimants are free to stake new mining claims on solar or wind project sites while a right-of-way application is pending (except where lands have been segregated as described below).

While it is relatively easy and inexpensive to file a mining claim, it can be difficult, time consuming and costly to demonstrate that the mining claim was not properly filed or does not contain a valid discovery. While some mining claims filed on land where a right-of-way application is pending may be valid, many others are likely to be speculative and not located for true mining purposes. Instead, many of the suspect claims are filed for no other purpose than for the mining claimant to compel some sort of payment from the project developer. BLM reports that over the last two years, 437 new mining claims were staked on land where developers have applied to build new wind farms and 216 new mining claims were located on where developers have applied to build new solar projects. Of course, this is exactly the sort of uncertainty that can discourage lenders from financing these projects.

In an effort to address such conflicts, BLM proposed new rules in April 2011 that would give BLM the ability to "segregate" lands temporarily for which wind and solar developers have applied for rights-of–way, as well as lands that BLM has identified on its own as promising for potential wind or solar development. Once segregated, the land would be off limits for new mining claims for a period of up to two years.

BLM put an "interim" version of the proposed rules into effect immediately on April 26, 2011 and collected public comments to the rules through June 27, 2011. BLM is currently analyzing the comments received. In the meantime, the agency temporarily segregated 24 tracts (677,000 acres) of lands previously identified as "solar energy zones" in Arizona, California, Nevada, New Mexico and Utah in June 2011.

Lenders raise four broad issues with BLM leases.

Unfortunately, segregation does not completely solve the mining claim issue, as neither the interim nor proposed rules affect mining claims that were properly located before the land in question was segregated. Consequently, rights-of-way applicants (and their lenders) must do careful diligence to ensure that projects can be constructed and operated in harmony with pre-existing mining claims.

Notably, BLM is also seeking a five-year withdrawal of the solar energy zones from all mining claims or activity. According to BLM, temporarily segregating the solar energy zones for two years under the interim rules will give the agency time to complete the necessary environmental and other reviews necessary to assess their future solar energy potential.

Litigation Risk

Lenders typically will not commit to projects that are mired in litigation — at least, litigation that is viewed as a credible threat to development.

Perhaps because of this, neighboring landowners, environmental advocacy groups, Native American tribes and others often file suit to block rights-of-way for solar and wind projects in the hope of stopping the projects.

The central allegation in most of these challenges is that BLM did not comply with the National Environmental Policy Act or "NEPA" before issuing the right-of-way in question. NEPA does not expressly provide for the right to judicial review; instead, judicial challenges are brought under the Administrative Procedures Act, which has a six-year statute of limitations. Notwithstanding the six-year statute, because of standing and other procedural hurdles, an immediate NEPA challenge under the APA offers an opponent the best opportunity for success. A site with threatened or endangered species of plants or animals gives a challenger additional ammunition. Having the right-of-way for a project rescinded is the ultimate goal, but many opposition groups consider it a victory just to delay a project long enough for its financing to fall apart.

If an opponent has up to six years after a right-of-way for a project is issued to challenge it, how on earth can any project be financed?

The answer is the longer the opponent waits to file a lawsuit challenging the right-of-way, the less likely a court will be to award the injunctive relief sought by the opponent. To order construction halted, a court must weigh the balance of benefits and harms if the project is built versus if the project is not built, taking into consideration practical matters such as the state of construction and the procedural validity of the right-of-way. If the opponent did not challenge the right-of-way by asking for an immediate preliminary injunction before construction started, then the passage of time is likely to tip the balance against granting an injunction. ◎

Environmental Update

California moved closer in late October to capping greenhouse gas emissions from power plants in the state. New caps on carbon dioxide (CO_2) and other greenhouse gas emissions from power plants are expected to take effect starting on January 1, 2013 with more far-reaching restrictions soon to follow.

The California Air Resources Board — called CARB — voted unanimously on October 20 to limit greenhouse gas emissions and create a comprehensive statewide cap-and-trade program. The California Office of Administrative Law must now review the program to ensure that it complies with the state Administrative Procedures Act.

The board is implementing a program that the state legislature adopted in 2006 in a bill that Californians call AB 32. The bill requires the state to reduce greenhouse gas emissions to 1990 levels by 2020, and it requires CARB to implement a program by the end of this year to achieve this goal. AB 32 was signed by then-Governor Arnold Schwarzenegger. California voters defeated a ballot initiative in November 2010 that would have overturned it.

The program caps the amount of CO_2 and other greenhouse gases that power plants, refineries, chemical companies, cement plants and other affected emitters are allowed to release each year. Each covered emitter will be issued a permit allowing it to emit a set amount of greenhouse gases per year. The program is market based because anyone who can reduce his emissions more efficiently or less expensively can earn income by selling his unneeded emission allowances to those whose emissions are harder or more expensive to control. As the cap on overall permitted emissions ratchets down over time, the value of the permits should rise and the overall level of greenhouse gases entering the atmosphere should fall.

Initially the program will cover only the power and manufacturing sectors (including refineries but only for their "direct emissions"). By 2015, the program will expand to cover a far broader range of emitters than is covered by existing cap-and-trade programs in other US states and Europe with its scope set eventually to reach 85% of the California economy, including not only electricity generation and manufacturing, but also such sources as refineries, pipelines and fuel distributors. By way of comparison, the Regional Greenhouse Gas Initiative that currently covers 10 northeastern and mid-Atlantic states (New Jersey announced it would withdraw by year's end) only covers emissions from power plants.

Beginning in January 2013, the program will require "covered entities" — defined to include the 600 largest emitters, such as power plants, refineries and distributors of both natural gas and transportation fuels — to hold and ultimately surrender emission allowances equal to their greenhouse gas emissions by 2015. Each allowance permits the holder to emit one metric ton of CO_2-equivalent. The number of allowances issued by the state annually will equal the cap on overall emissions. That cap will decrease at a set rate through 2020. Compliance obligations for covered entities begin in 2013 and, as the cap tightens, market pressure from fewer available allowances should, in theory, require covered entities to reduce their emissions or pay the market price to comply.

The program will have an effect beyond California's borders by imposing compliance obligations on emissions associated with electricity, natural gas and other fuels imported from other states into California. This is the first regulatory program to regulate suppliers of power and fuels in other states who sell into the California market.

The new rules cover "first deliverers of electricity," who include not only in-state electricity generating facilities, but also "electricity importers." "Electricity importers" are defined as "facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system." Thus, even facilities located entirely outside California may be required to comply if their energy is sold in the state.

Similarly, the program may apply to out-of-state suppliers of natural gas and other fuels whose products sold in California reach an annual threshold of 25,000 tons or more of CO_2-equivalent from emissions from combustion or oxidation of the fuels.

Initially, CARB will distribute most allowances for free among the covered entities according to a complex set of factors such as regulatory exposure of various sectors and efficiency goals. As time passes, an increasing proportion of allowances will be sold in quarterly auctions. As more allowances enter the market via auctions and the overall cap is lowered, the cost of emitting greenhouse gas for many covered entities should increase.

The new CARB rules should limit wild swings and increase stability in the auction market. To prevent prices from falling too low, the early auctions will have a price floor of $10 per allowance, adjusted over time. Unsold allowances are returned to the state's "auction holding account" and will be re-sold at later auctions, subject to the limitation that only 25% of an auction's total volume may include such re-auctioned allowances.

To prevent prices from rising too high too quickly, most allowances will be given away initially for free. As auctions account for distribution of progressively more allowances, there will be an allowance price containment reserve. This reserve will offer allowances for sale six weeks after each auction at set price tiers ranging from $40 to $50 a ton at first, adjusted over time.

The CARB program establishes three compliance periods. The first runs from 2013 to 2014, the second from 2015 to 2017 and the third from 2018 to 2020. Each covered entity must true up its allowances with its emissions for the prior compliance period by November 1 of the following year (for example, by November 1, 2015 for the first compliance period). However, the program requires that covered entities surrender allowances equal to at least 30% of the previous year's emissions by November 1 in years that are not true-up compliance years.

The program also creates a domestic offset market. Covered entities can meet, or "offset," up to 8% of their compliance obligations by surrendering valid greenhouse gas offset credits. Unlike reductions in emissions by the regulated entities themselves, the reductions backed by such offset credits may be generated by anyone anywhere in the country. However, to qualify under AB 32, the offset credits may only be obtained in three ways. First, certain "early action offset credits" generated between 2005 and 2014 pursuant to the protocols of the Climate Action Reserve may be converted into credits that CARB will issue. Second, CARB expects to issue its own offset protocols. Third, CARB expects to allow use of credits registered under some third-party offset project registries.

California receives nearly a quarter of its power from out-of-state sources. Regulated entities often hold a broad array of generating facilities. The program attempts to prevent circumvention of compliance obligations by what CARB calls "resource shuffling." This basically amounts to importing power from out-of state power plants with fewer greenhouse gas emissions for use in California while exporting more emissions-heavy power from California to avoid its regulation.

According to The New York Times, of the 121 million tons of greenhouse gas emissions associated with the California economy in 2010, 37% came from the power industry, 28% from refineries, 10% from oil and gas extraction, 9% from stationary combustion, including industries from glass makers to sawmills to dairies, 9% from electrical cogeneration, and 5% from the cement industry. With the effective date of the program approaching and the first allowance auction scheduled for August 15, 2012, the requirements may give large emitters an incentive to hedge their exposure early rather than wait for the auction.

Utility MACT

The deadline for the US Environmental Protection Agency to define what it considers the "maximum achievable control technology" or "MACT" for controlling certain emissions from coal-fired power plants has been pushed back to December 16.

The agency received more than 900,000 comments to its proposed rule. EPA estimates that about 10,000 megawatts of coal-fired power may be taken out of service as a result of the rule to install MACT at such facilities, although many believe the number will be much higher. There are concerns about the potential effect on grid reliability if so many power plants are retired. The Federal Energy Regulatory Commission will hold a technical conference on November 29 and 30 on the reliability of the US bulk-power system, including the potential impact of the new EPA rules.

The EPA "utility MACT" rule describes pollution control equipment that will have to be used at certain power plants to reduce acid gases, non-mercury metals and mercury. MACT for existing power plants is determined based on the average emissions of a subset of best-performing facilities.

Existing air emissions controls already used at the facilities to reduce emissions of particulate matter, SO2 and NOx also help reduce mercury emissions. A October 2009 report by the US General Accounting Office, an arm of Congress, entitled "Clean Air Act: Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions," said roughly 25% of existing coal-fired power units achieve at least a 90% reduction in mercury emissions through exiting pollution controls. The efficiency of existing controls with respect to mercury depends on a number of variables including plant configuration and type of coal burned. Additional controls like activated carbon injection may be needed to increase the efficiency of these systems with respect to mercury removal.

/ continued page 68

Environmental Update

continued from page 67

The additional controls can be very expensive to install and maintain. Developers and lenders will have to take their calculators out to figure the costs.

Cross-State Air Pollution Rule

The US Environmental Protection Agency released an ambitious "cross-state air pollution rule — called "CSAPR" and pronounced "Casper") — to replace the "clean air interstate rule" — called "CAIR" that was struck down by a US appeals court in 2008.

CSAPR will impose emissions caps that will require reductions in SO2 and NOx emissions from existing power plants in 27 states mostly east of the Mississippi River, but as far west as Texas.

CSAPR addresses the interstate transport of SO2 and NOx from upwind to downwind states. Tension is building between industrial, upwind states over what they see as new costly regulations that will shackle their economies for the benefit of downwind states with big cities.

The new rules go into effect on January 1, 2012.

Critics in the upwind states fear the rules could lead to rolling blackouts during peak summer months. They also complain that the capital outlay some power plants will have to spend on pollution control to comply will significantly increase the cost of electricity.

Reaction to the new rules has been swift. Numerous parties asked EPA to reconsider the rules before the October 7 deadline for such requests. Ameren, a large mid-western utility headquartered in St. Louis, said it will close two power plants primarily due to the expected costs of complying.

A number of lawsuits have been filed to block the new rules and have been largely consolidated in EME Homer City Generation L.P. v. EPA before the US appeals court in Washington, D.C. Seven northeastern (downwind) states moved on October 19 to intervene in the case to defend the rule.

Cooling Water Intake Structures

Compliance with an EPA proposed rule on cooling water intake structures could be very costly and lead to retirement of some older power plants, particularly after the costs are added to the expected costs to comply with CSAPR and utility MACT.

Many older power plants use once-through cooling. The alternative is closed-cycle cooling that uses much less water because the cooling water is recycled. Facilities with once-through cooling will face much higher costs to comply with the new rule on cooling water intake structures. The government is concerned about impingement and entrainment of aquatic organisms. Impingement occurs when aquatic organisms are trapped against cooling water intake screens. Entrainment occurs when such organisms are drawn into a facility.

The proposed regulations would apply to existing facilities with permits to discharge storm or wastewaters and that have water intake structures with design intake flows of more than two million gallons of water per day and that use at least 25% of that water exclusively for cooling.

Compliance with impingement restrictions may require installation of additional screens and reduction of water intake flow rates. New units at existing facilities would probably be required to install technology equivalent to closed-cycle cooling. A final rule is not expected until July 2012, and some facilities may have up to eight years to comply with the requirements.

—contributed by Sue Cowell and Andrew Skroback in Washington and Alice Bodnar in Los Angeles.

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