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Renewable Energy Update

The share of electricity supplied from renewable forms of energy is 90% in Norway and 59% in Austria. The average is 15.7% for the 25 countries of the expanded European Union. Renewables have farther to go to catch up in the United States, but they are the fastest growing segment of the US market.

A panel of six experts talked at a Chadbourne conference in June about the use of wind, sunlight and biomass to generate electricity in the United States — where is most of the action, what returns are equity investors earning, have wind farms performed as expected, is the United States on the verge of a boom in solar projects, and what is the biggest risk for investors putting money into renewables?

The panelists are John Eber, managing director of energy investments at JPMorgan Capital Corporation, Lance Markowitz, a senior vice president and head of the equipment leasing division at Union Bank of California, Ned Hall, vice president of wind generation at The AES Corporation, Ciaran O'Brien, senior vice president for finance for the US subsidiary of Irish wind company Airtricity, Rhone Resch, president of the Solar Energy Industries Association, and Brian Robertson, chief financial officer of SunEdison. The moderator is Keith Martin from the Chadbourne Washington office.

Size of Wind Market

MR. MARTIN: John Eber, can you give us a sense of how large the wind market is in the United States for equity investors who are prepared to take part

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TRANSACTION STRUCTURES and some tax planning ideas are patentable, but should they be?

A House subcommittee held a hearing on the subject in July. Committee staff said that if the practice becomes more widespread, it could force tax lawyers to research whether someone has already applied for a patent on every tax-planning idea before using it with a client.

Internal Revenue Service Commissioner Mark Everson testified at the hearing that none of 14 patents the agency has studied so far involves an abusive transaction. The subcommittee chairman, Dave Camp (R.-Michigan), is a critic of the practice of granting such patents.

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of their returns in the form of tax benefits? How many deals are expected this year?

MR. EBER: The market has expanded considerably. We have seen seven deals come to market so far this year for about 1,100 megawatts, and we are expecting at least five more for maybe another 1,200 megawatts. That would be a sizeable increase over what we have seen in prior years.

Only 12 wind projects or portfolios of such projects are expected to go to market this year in search of tax equity.

MR. MARTIN: How many deals were there last year?

MR. EBER: Final count, I think we had about 600 megawatts and maybe five transactions.

MR. MARTIN: Those are just the deals where wind companies need investors who can use the tax subsidies that the US government offers on wind farms, correct? Those are not the figures for all wind farms that went to financing last year in the US market.

MR. EBER: Correct.

MR. MARTIN: Ned Hall, turning to the nature of the US wind market, there are just a few dominant wind developers, and there are others who are trying to gain market share. Who are the dominant players, and who are the up and coming?

MR. HALL: Of course, I would like to think AES will be a dominant player. The way we try to differentiate ourselves is we bring a global footprint, about 26 countries, to our mix. Our strategy started out as a focus in the US, spreading to Europe and very quickly to the rest of the world. Since I am sitting here with Airtricity, I need to respect their accomplishments, especially in a very short period of time in the US market. I think they will be one of the top five constructors in the next two years, given the numbers that they are talking about. Obviously, everybody is playing catch up to FPL and PPM.

MR. MARTIN: So the biggest is FPL Energy. What share of the market is FPL Energy?

MR. HALL: They are approaching 4,000 megawatts out of a total installed capacity in the US of 12,000 to 13,000 megawatts, and they are probably adding 600 to 800 megawatts a year. I think to be a serious player, you need to get to scale of more than 500 megawatts, but no one other than FPL is probably approaching 1,000 megawatts at this point.

MR. O'BRIEN: I concur. I think what you will see is FPL will eventually settle around 20% of the market going forward, and the other players like PPM Energy and AES will start catching up, but FPL are so far out in front at this point that it is difficult to see other people catching up very quickly.

MR. MARTIN: Let me offer some statistics. Current capacity is 9,134 megawatts. The figure 12,000 to 13,000 must count what is currently under construction.

MR. HALL: Yes. Worldwide, wind companies installed around 11,500 megawatts last year.

MR. MARTIN: In 2005 in the US, 431 megawatts were installed. This year, 3,000 megawatts are expected in additional capacity in the US. Lance Markowitz, what other types of projects are you seeing besides wind in the renewable sector?

Other Renewables

MR. MARKOWITZ: People are coming in to talk about solar. There is some activity in geothermal. Biomass is also under discussion, but frankly, wind is the dominant player at the moment in terms of activity. Wind accounts for at least 80% of the renewables market.

MR. MARTIN: John Eber, you have some data, too?

MR. EBER: In terms of megawatts, wind is over 90% of what we are looking at for this year. In terms of dollars, it is probably 85% because solar is so expensive on a per-megawatt basis.

MR. MARTIN: What else have you seen besides wind?

MR. EBER: We are seeing a little bit of solar. There are a couple large solar transactions in the market and maybe a couple geothermal deals and a few biomass as well.

MR. MARTIN: Have any solar deals closed to your knowledge?

MR. EBER: I haven't seen any of size.

MR. MARTIN: Brian Robertson, have you seen any?

MR. ROBERTSON: We closed a fund called Sunny Solar Fund with Goldman Sachs and Hudson United Bank last year. We expanded that this year to double in size. It's a collection of about 30 smaller projects. One of the problems with solar projects is they typically sit behind the customer's meter. They go on rooftops. They are smaller distributed generation facilities, so we batch them up into larger tranches so that the deal has enough scale to interest someone like John Eber.

MR. MARTIN: Have any biomass deals closed this year?

MR. EBER: On the equity side, I have not seen any that have closed.

MR. MARTIN: Lance Markowitz, have you seen any biomass deals close in the last year or two?

MR. MARKOWITZ: One.

MR. MARTIN: Why is biomass so slow to take off? Wind is the lion's share of the market, and solar is up and coming.

MR. HALL: My view would be price. Wind is the lowest-cost renewable. Biomass, solar and everything else is still in the double digits in terms of price per kilowatt hour. In the case of biomass, it has been very difficult to find reliable sources of fuel. A lot of attention has been paid recently to efforts to use crops that are specifically grown for use as fuel, but no one has reached construction on a project using "closed-loop" biomass as far as I am aware.

MR. EBER: Another reason that biomass has been slow to develop may be that such projects were only recently made eligible for production tax credits. When production tax credits were first authorized for biomass projects in late 2004, it was only for five years of credits. The tax subsidy was not overpowering. The energy bill last August extended this to 10 years. These projects are longer in the development pipeline.

MR. MARTIN: The average share of electricity generated from renewables in the countries of the European Union is 15.7%, but it reaches as high as 90% in Norway and 59% in Austria. Any idea what it is in the United States?

MR. HALL: Counting hydroelectricity, it is about 10%.

MR. MARTIN: Any idea what share of that 10% wind represents?

MR. HALL: It is probably less than 1% of the 10%.

MR. MARTIN: And solar is?

MR. O'BRIEN: Less than one tenth of 1%.

MR. MARTIN: So there is enormous */ continued page 4*

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The US Patent Office has issued 40 patents on tax products and has another 60 applications pending. Many of the patents are for computer software that carries out tax calculations rather than for tax-planning ideas. Some also involve tax planning as part of a larger business strategy. For example, US patent number 6,772,128 involves a method for using an insurance policy combined with a trust to cover the cost of decommissioning nuclear power plants. The patent claims the method produces tax efficiencies, but the main focus is on the structure for the insurance.

Patents can be obtained for "business methods" that are both novel and not obvious.

A report that the Joint Tax Committee staff prepared for the hearing suggested there is concern that tax patents allow the holders essentially to claim a property right in the US tax code and to charge economic rents from others for merely trying to work within the US tax laws. The staff report also raises questions about whether tax planning is the type of the innovation that the patent system was intended to encourage. It is not clear whether any legislation will follow from Congress.

Meanwhile, a small advisory firm in Florida has sued the chairman of the Aetna insurance company for establishing "grantor retained annuity trusts" funded by nonqualified stock options. The firm says it holds a patent on the idea. The case is Wealth Transfer Group LLC v. Rowe.

IMPROVEMENTS to property are sometimes hard to distinguish from repairs.

The IRS proposed voluminous new regulations in late August in an attempt to draw clearer lines.

The line-drawing is important for companies that spend money to maintain existing power plants, pipelines, electricity grids, roads and other assets. If the spending is classified as a "repair," then it can be deducted immediately. If it is an improvement, then the spending is considered an additional */ continued page 5*

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potential for growth. Rhone Resch, what is the rate of growth overseas in solar energy installations?

MR. RESCH: For the last six years, we have seen a compound annual growth rate of 37% in solar, driven mostly by Germany and Japan, and with the United States in third place. The growth rate in the US over the same time period is about 6%.

Equity Returns

MR. MARTIN: Focusing still on our two equity investors, what returns should an equity participant investing in renewables expect in the current market?

MR. MARKOWITZ: For tax equity deals without any debt, returns have been 7% to 8% and trending downward in the last couple years from higher levels. For leveraged deals, it gets pretty dangerous to quote numbers because there are so many different structures and levels of risk, but the returns are closer to double digits.

MR. MARTIN: Interest rates are trending upward. Is that expected also to push up equity returns?

MR. EBER: It should. The number of potential equity investors has been small for the last couple years, but as the number has increased, there has been more price competition. More importantly, those of us who have been doing deals have gotten more comfortable with them and are willing to take a little lower return thinking that we understand the business risks a little better. So, they should go up, but they haven't. Time will tell.

MR. O'BRIEN: Sorry, John. I think I'd prefer to see the market talk about spread over 10-year interest rates as opposed to those kinds of figures. This has always caused a big problem at wind conferences. People get figures in a form that makes it hard to compare structures. In an unleveraged deal, which is probably the biggest part of the market, we think the spread over 10-year interest rates should be very close to project finance-type yields, which is about somewhere between 120 and 175 points, depending on the structure.

MR. EBER: Tax equity has never been the priced the same as debt. It is a scarcer commodity. You know if you lend money, you will be paid back. If you invest equity, you will share in tax subsidies that have value only if your corporation can use them over the 10-year period such subsidies are offered to wind farms. The debate ought really to be what premium equity should get over debt for using the corporate tax capacity.

MR. MARTIN: Is there any reason to think that returns would be any different for the solar market or for biomass than they are currently in wind?

MR. MARKOWITZ: Sure. Solar and biomass are more shallow markets. Developers have fewer investors with a good enough understanding of risk to bid. There may also be a perception that the risks are a little higher.

MR. RESCH: It is also a very different product. When you look at solar, you are providing peak power. It is 8 a.m. to 6 or 7 p.m. every day. There is a different pricing mechanism for solar. I would argue that in states like California, you will receive a premium for that product so that the margins should be greater.

MR. MARTIN: Brian Robertson, you were chafing.

MR. ROBERTSON: Yes. We have been looking at debt and tax equity term sheets in some larger projects that we have under development. We have had some success making the case that the equity returns should be lower for a leveraged solar project than a wind project because the solar tax credit is taken at inception. There is no risk of losing the ability to take part of the tax credit over time. Sunlight is also a more stable resource. It is less variable than wind. There are no moving parts in the typical solar project, and the assets have a 25-year life. We view solar as less risky than wind, and other people are starting to see it that way, too.

MR. RESCH: You also have to figure that solar is perhaps seven years behind wind. We did not have the luxury of the production tax credit. We still do not have a production tax credit, but we have an investment tax credit. That 30% investment credit has been in effect for maybe five months, and already we are starting to see a lot of interest in it. I think what you will see in the next 18 months is how the industry can put it to work.

Too Much Equity?

MR. MARTIN: There has been a perception in the market in the last year-and-a-half to two years that there are too many equity chasing after just a handful of deals. I am starting to wonder whether this view is correct.

MR. MARKOWITZ: I think that is absolutely correct. It was less true a couple of years ago, but now there seems to be a renewables conference every week, and you see hundreds of people at these conferences. And that is for a wind market with maybe 10 deals.

MR. EBER: I agree. It is not as big a market as people think. It was four or five deals a year for three years in a row. There will be 12 deals this year. There is a lot of pent-up demand. The developers on this panel will tell you they get called on by a lot of prospective equity investors.

MR. MARTIN: Ned Hall, are you having money thrown at you by people who are desperate to get into the wind market?

MR. HALL: It's not quite like the Dilbert venture capitalist yet, but hopefully, we will get there. It is not as robust right now as the bank market. Obviously, there have been very significant new entrants on the equity side. The partnership flip model for equity participation is still relatively novel for a lot of people, but there have probably been enough projects closed using that model that we are seeing broader acceptance in the advisory and investing communities. Frankly, one reason why the FPLs and PPMs have been dominant in the wind market is the other developers lacked the tax appetite to take full advantage of the tax subsidies. It was actually enjoyable to hear Mike O'Sullivan of FPL say at the Global Windpower 2006 conference that he is starting to feel the heat.

MR. O'BRIEN: I would add that one of the things that acted as a constraint for developers was the need to get 15-year contracts to sell electricity to secure financing and the fact that contracts were awarded through RFP processes. That made the thing very complicated, as did the fallout after Enron collapsed. When I arrived here two years ago, you could not talk to anyone about a power trade for seven years or a gas hedge. Today, all the investment banks have power traders and they are able to provide developers with alternatives to power purchase agreements in some markets. The equity investors who are looking for purely contracted deals should know the market has moved on. Today, we are into synthetic power purchase agreements with hedges.

When you look at these deals, the tax subsidies account for 60% or 70% of the returns. The equity should be focusing on the quality of the hedge counterparty rather than chasing down contracted deals.

Solar Surge?

MR. MARTIN: Let's switch focus now to solar. There was an interesting quote in sparkspread.com earlier this month. Jim Wright, who is a former managing director of Carlyle/Riverstone, has launched a fund to / continued page 6

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investment in the facility with the result that the cost must be recovered over time through depreciation. Maintenance costs more to the extent the cost cannot be deducted immediately.

In general, spending is considered an improvement rather than a repair if it materially increases the value of an asset, substantially prolongs its useful life or adapts the asset to a new or different use.

One of the most difficult issues, when trying to decide whether the value of an asset has been materially increased, is how to figure out what is the unit of property. Spending $100,000 in a year on a power plant may be insignificant if the asset is the entire power plant, but it is material if the asset is just a conveyor belt. The IRS said it does not think the appropriate unit of property is an entire power plant. It adopted a three-part test for how to break a project into smaller pieces.

The taxpayer is supposed to make a first cut by treating as a single asset all the property that is functionally and integrally related. This first cut identifies the largest possible single asset.

Then the taxpayer must make a second cut. For companies that are in regulated industries, the second cut is easy. They must break the project into the separate asset categories in the uniform system of accounts used by the Federal Energy Regulatory Commission, the Federal Communications Commission or the Surface Transportation Board.

It does not matter whether the particular company is actually regulated. Thus, for example, tax departments at independent power companies and private equity funds that invest in power projects will have to become familiar with the FERC asset accounts. All electric, gas, water, telecom, cable television and transportation companies will be treated as in regulated industries and will be required to use these accounts.

For companies in other industries, the largest possible asset identified in the first cut must be split as follows. First, treat each building and its structural components, like wiring and floors, as a single asset. Second, divide / continued page 7

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invest in utility-sized solar projects. "There is a perfect storm developing in solar," Wright said. He said he is aware of some 50 solar projects that are awaiting financing. Rhone Resch, do you have the sense that there is a tremendous surge in solar projects all of a sudden and, if so, what is driving it? Is it the 30% investment tax credit?

MR. RESCH: No, it is not. There are 22 states and the District of Columbia that have renewable portfolio standards that require utilities to supply a certain percentage of their electricity from renewables. The biggest states for solar are California and Arizona. Many of these RPS states have solar set-asides or solar carve-outs. We see a market of between 7,000 and 8,000 megawatts in the next 10 years driven mainly by the California solar initiative and the renewable portfolio standards at the state level. In 2005, just for comparison's sake, we installed about 105 megawatts of photovoltaic cells and one megawatt of concentrating solar power.

MR. MARTIN: Are you seeing membership surge in your trade association?

MR. RESCH: In the last two years, we have gone from about 70 members to 220 members. So, yes.

MR. ROBERTSON: One hundred megawatts of solar equates to about $600 million of purchases of systems. Three years ago, 100% of solar was purchased by an end customer. They just paid cash, and that was it. The market is moving today to PPA models where the customer is just buying electricity under long-term contract; he or she is not buying the solar system. Approximately $100 to $120 million of the $600 million will be financed this year based on offtake contracts. You would not have seen solar showing up on an institutional financier's radar before now.

MR. MARTIN: There are two types of solar projects. What are they?

MR. RESCH: The first is concentrating solar power and this is desert southwest for the most part. There are three different technologies, but the one with which everyone is most familiar is a parabolic trough that concentrates the light on to a receiver tube that has oil or molten salt that runs a Rankine cycle power plant with natural gas as a backup fuel. There is one such plant under construction today in Nevada. It is a 64-megawatt plant in Boulder City, Nevada. There are about 1,500 megawatts of PPAs for other types of concentrating solar power plants. These are utility-scale power plants.

The solar market worldwide is growing at a 37% annual compound rate. Germany, where sunlight has the same intensity as in Anchorage, Alaska, currently dominates the market.

The other technology is photovoltaics, or PV, as a direct conversion of sunlight to electricity. That's what I have on my house. That's what you tend to see powering street signs and telecommunications facilities around the country. But you are also beginning to see it on on commercial roofs in large, increasing numbers in states like California, Nevada, Arizona and New Jersey.

So, there are two very different types of projects. One type might be 50 to 300 megawatts in size, while the other is in the single digits to tens of megawatts potentially.

MR. MARTIN: Brian Robertson, on what type of project is SunEdison focused?

MR. ROBERTSON: We are focused on two types of deals that correspond to the two types of technologies. We are working on utility-scale deals where the financing is based on the credit of a utility. We are also working on distributed generation photovoltaic projects. In PV projects, you are financing based on PPAs with retail customers — for example, big box retailers with multiple installations.

When you compare cost of power with people talking about wind at $60 a megawatt hour, fully delivered retail power from solar at peak times is more like $150 to $200 a megawatt hour.

MR. MARTIN: Perhaps one reason solar is taking off more rapidly in Europe is that people there are accustomed to paying 25¢ or 30¢ a kilowatt hour while, in the United States, we are not. How does solar make headway in the United States when the cost of solar electricity remains so high?

MR. ROBERTSON: Fossil fuel prices are helping us by driving up retail electric rates. In some states like Hawaii, we are only a year or two away from solar being cost competitive without a subsidy. In states like California where PG&E has raised rates by 20% this year, solar electricity is at 16¢ or 17¢ a kilowatt hour. We are four or five years away from being able to compete on cost, but it is not a pipe dream. There is a path to get there. This is a market by market and utility by utility determination.

Three things are contributing to the growth in solar today. One is the federal investment tax credit. It went from 10% to 30% this year. The second is electricity rates are going up rapidly in many parts of the country, scaring consumers who have no effective way to manage the volatility. Third is the myriad state incentives that sometimes are in the form of an upfront grant and sometimes are in the form of a production-based incentive where the generator is paid by the kilowatt hour of renewable energy it produces.

MR. RESCH: The other trend in evidence is the price is coming down. We have seen an historic decrease of about 6% per year in the cost of photovoltaics, and I think we will see an even greater decrease in the cost of concentrating solar power in the near term. Part of this is due to the influx of new manufacturers in the last couple years. The manufacturers now include such companies as General Electric, Kyocera, Sharp, BP, Shell, Sanyo — both big electronics manufacturers and big energy companies. This means there is competition both on the technology side and in the scale of manufacturing that is unprecedented in the solar industry. It is this competition that is driving down prices.

Potential Growth

MR. MARTIN: The big story at the Global Windpower 2006 conference this week is that the industry has set its sights on a 20% share of the US electricity market within 10 years. Ned Hall, do you think that is achievable?

MR. HALL: I think you have to expand your thinking to the world and focus on the level of worldwide demand versus manufacturing capacity. The simple answer is we can achieve whatever we are willing to pay for. To meet a target of 20% or even 10% of the US market, you would need to think of wind turbine manufacturing as appliance manufacturing. The industry would have to make a new turbine ever 15 minutes and a blade every five minutes to get to the volume needed. The infrastructure to do this is not in place today. There are two obstacles tied to price: will we pay the / continued page 8

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up any other real property, like land, parking lots and fences, into separate assets using common-sense lines. Finally, use four rules of thumb for breaking down the machinery and equipment into separate assets. One rule of thumb is that pieces of equipment that the taxpayer acquires from separate vendors are probably separate assets. Another rule of thumb is to look at what the company does on its financial reports or books. If it has assigned different useful lives for computing book depreciation to different parts of a project, then these lines are a guide for breaking a project into separate assets for tax purposes. Another rule of thumb is to treat equipment that performs a different function than the rest of the machinery as a separate asset. Finally, rotable spare parts are treated as separate assets. A rotable spare part is a spare part that a company takes out of one machine, repairs, and then reinstalls in a different machine.

A company must then do a third cut. If it has treated a piece of equipment as a separate asset for any other federal income tax purpose, then it is bound by that division. An example is where a power company claims a loss on grounds that it abandoned X asset. It cannot claim later than an asset like X is actually part of a larger unit of property.

The new rules do not apply to "network assets." Examples of network assets are oil and gas pipelines, electric transmission and distribution lines, gas, water and sewer mains, and telephone and cable lines. The IRS is still struggling to come up with rules for them.

The IRS declined to set a single percentage that in all cases would be considered material. However, it appears that an increase of at least 25% in value will always be material.

The IRS said it would use a "*Plainfield-Union* test," named after a court decision that the agency had refused to accept in the past, for testing whether spending has materially increased the value of an asset or substantially prolonged its useful life. By definition, any repair to a piece of equipment that / continued page 9

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price, and will the price motivate enough manufacturing to meet the targets?

MR. MARTIN: The point is the wind industry has big ambitions. What are the ambitions of the solar industry?

MR. RESCH: We start with a very, very small base. We are a decade behind wind in terms of getting used to the incentives and growing the business. In terms of the global market, Germany is the leader in installing photovoltaics. The Germans install more than eight times the amount of PV that we install here in the United States. Germany has the intensity of sunlight of Anchorage, Alaska, and yet it dominates the world market. This makes no sense.

With respect to solar, it is not a matter of if; it is a matter of when. The resource potential of the United States is unlimited. The Western Governors Association will issue a report on Monday that identifies about 10,000 megawatts of solar that will be installed in the next decade just in the western states.

Then consider New Jersey, which is the second largest solar market in the United States. Why New Jersey? Because New Jersey is finding it cheaper to invest in solar to stabilize the grid and ease congestion on transmission lines than to build new power plants or build new transmission lines. We are starting to see public utility commissions and even utilities get into the game in order to stabilize the electricity infrastructure.

MR. MARTIN: One interesting statistic from the *Wall Street Journal* yesterday was the photovoltaic market had $11.2 billion in investment in 2005, but is expected to grow to a $50 billion industry by 2015. However, the growth won't come in the next two years, right? There is a severe shortage of polysilicon for making PV units.

MR. ROBERTSON: Demand has gotten ahead of the supply. There is no question about it. Demand is driven by the programs in Germany, Japan, Spain and South Korea. These countries have launched programs that make it more economically attractive for manufacturers to supply to those markets than to the United States.

Every single manufacturer is looking at the United States and the laws that have been enacted at the state level and saying the US will be the biggest market in the world by 2008 or 2009, but the manufacturers still sell their modules in the meantime to buyers in places like Germany because that is where they fetch the highest price. Every manufacturer is selling a little capacity into the United States in order to maintain a foothold. The challenge for solar companies like SunEdison is to convince the manufacturers to establish a full presence here earlier rather than later. It is a significant challenge.

MR. O'BRIEN: In the wind business, you have a global market for equipment and subcomponents. Wind turbines are an assembly of a lot of different subcomponents made all over the world. And if elsewhere, they are willing to pay the prices, that is where the turbines will go. The United States will be short wind turbines for a number of years because it has not yet seen a massive increase in manufacturing capacity, and places like India and China are getting the lion's share of the turbines going forward. There are physical limits to supply. The production tax credit compounds the difficulties. Because it keeps expiring and has to be renewed by Congress, manufacturers are not prepared to commit to build factories in this market. The only two new entries have been Gamesa from Spain with a factory that will build 300 to 400 megawatts in turbines a year and Mitsubishi with an additional 300.

MR. MARTIN: Those are enough turbines for three or four projects a year.

MR. O'BRIEN: That's all it is in this market. Something significant will have to change for wind truly to take off.

MR. RESCH: That's definitely the case with solar as well as Brian Robertson pointed out, but one of the things that we are seeing is innovation. We are seeing new technologies and, perhaps where wind was a decade ago, we are starting to see new companies enter the market with new manufacturing techniques drawn from the high-tech industries. New flexible thin film products should be available commercially later this year, and although the market is currently about 95% polysilicon based, I think that will shift. There will be new entrants in the thin film market. This should lead rapidly to an expansion in supply because they don't have the silicon feedstock restrictions.

Also, what is happening on the poly side is pretty exciting. We expect a full doubling of capacity in polysilicon in the next two years, with all of it dedicated to the solar market. We used to get the scraps of the polysilicon industry. We now represent more than 50% of the market for those who manufacture polysilicon. In two years, we will be more than 70% of the market. The bottom line is there is a rush to increase manufacturing capacity, and we think the shortage will be behind us in a short time.

MR. HALL: What I find interesting is that the market for all of solar, wind and other forms of renewable energy is really established by the state renewable portfolio standard programs, and the number of such programs is increasing. We expect more states to add legislation this year.

MR. MARTIN: These are laws like the 1978 Public Utility Regulatory Policies Act — or PURPA — that require utilities to supply a certain percentage of their electricity from renewables. They create demand for renewables.

MR. HALL: Yes, but it is a little different in a very important way. The utilities are not required to buy the electricity at any particular price. New York is probably instructive from that perspective. It passed legislation. It set up a quasi-government organization called NYSERDA to run auctions for renewable energy credits, and NYSERDA funds the program with a surcharge on retail rates. NYSERDA just spent what it had, and it made only about half of its target. There are other states that have programs. but with virtually no teeth in them, no penalty rates.

There is clearly price pressure in the entire renewable sector today due to increasing competition for the scarce manufacturing capacity. This country has a history of starting these types of efforts and then not being willing to pay what it really costs to implement the legislation. Examples are the Clean Air Act and CAFE standards. The big question for me is: will the RPSs hold given the prices that utilities are having to pay to secure the supplies of renewable electricity that they are required by law to have?

MR. EBER: Don't you think that RPS overall is probably more important or as important as the production tax credit?

On the possibility of a PTC extension, everyone is far more concerned today about energy dependence than the last time the PTC was up for renewal. The last time, oil was less than $40 a barrel. I see a lot of people making bets on 2008, and yet there is no production tax credit for 2008 as we sit here today. Yet, people are spending money and making commitments to buy wind turbines into 2008.

MR. HALL: I completely agree. It is really RPS driven at this point. Turbine manufacturers historically have had to give guarantees to cover your loss if they fail to deliver equipment in time to qualify for production tax credits. There are no such guarantees any longer. Today people are starting to buy 2008 machines when the legislative committee / continued page 10

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is broken increases its value or extends its life. The IRS said the comparison should be done by looking at the equipment before the event that necessitated the repair.

Spending is an improvement — rather than a repair — if it substantially prolongs the useful life of an asset. Larger companies that assign a useful life to particular kinds of assets on "applicable financial statements" will be required to use that life for purposes of comparison. The agency said the useful life is "substantially" prolonged if it is extended by more than one tax year beyond when it was originally expected to have to be retired.

Finally, the IRS said it would let companies claim an annual repair allowance. An amount of spending each year up to the allowance can be deducted. Any spending above that would have to be "capitalized," or added to the tax basis of assets. A company would have to file an election if it is willing to agree to this. Once an election is made, then a company will be bound by it for all future years unless it can persuade the IRS to let it revoke the election.

The proposed regulations include the repair allowance percentages. For example, annual spending on all equipment that is classified as 5-year MACRS property for depreciation could not exceed 10% of the original cost of such property. An example of 5-year property is a wind farm, solar power project or a power plant that burns biomass as fuel. The proposed repair allowance for 15-year property is 3.33% a year. It is 2.5% a year for 20-year property. An example of 15-year property is a simple-cycle power plant that burns gas. An example of 20-year property is a coal-fired power plant or combined-cycle power plant that burns gas.

The IRS is collecting comments on the new rules until November 20. They will not take effect until they are republished in final form. Meanwhile, the new business plan the IRS released in mid-August said the agency is working on a separate revenue ruling about when amounts that power companies spend on maintenance can be deducted.

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of the American Wind Energy Association is saying the likelihood that Congress will extend the production tax credit this year is less than 1%. And 2008 turbine capacity is selling out as we speak.

MR. MARTIN: Are there many projects today that have stalled due to inability to get wind turbines?

MR. HALL: There is a significant amount of excess development in the business. No doubt about it.

It doesn't work in most markets. As you move into the northeast, capacity factors come down dramatically to sub 30% so that you need a fairly substantial price for the renewable energy credits on top of the electricity revenue to support the project.

MR. O'BRIEN: We think in time that utilities will offer a premium for the benefits of adding a new fuel, like wind, to their resource mixes. We have not seen it yet. There is a benefit to having portfolio diversification.

MR. RESCH: You also need to factor in carbon at some point in the near future in the United States. We haven't discussed that yet, but the expectation is that additional costs will be imposed on electricity generators who use fossil fuels.

Developers are behaving as if US tax subsidies that expire in December 2007 are certain to be extended by Congress.

To kind of answer your question on solar, even though the price has gone up, installation cost has actually remained flat or gone down slightly. In California, the California Energy Commission data shows that the module cost is increasing, but there is more efficiency in the installation. The two offset each other with the result that the installed cost of solar systems has remained fairly constant.

MR. O'BRIEN: Another fact of life is the turbine manufacturers are using their leverage to force up prices. The turbine makers were not making money the last three or four years and they are making up for it this year with increases so far on the order of 20%.

MR. MARTIN: So there are big profits to be made currently not only in oil. There has been a surge in demand in the US for renewables, but it has led immediately to shortages of essential components. Let me give you another data point. Polysilicon normally costs between $42 and $60 a kilogram, which is 2.2 pounds, but prices have surged recently to as much as $150 a kilogram. Are we reaching the point in wind or solar markets where some projects that are under development are no longer economic to build because of the run up in prices for components?

MR. HALL: Absolutely.

MR. MARTIN: Is that a concern in every project or just a few?

MR. HALL: I think about it market by market. Will the market absorb the price that must be absorbed to make projects work? In the case of wind, it depends on your capacity factor and the fuel on the margin. In places like Texas, the higher turbine prices still work today. If you can get a high 30% capacity factor site with gas on the margin and can put a forward contract or PPA in place, it will work even before additional value is assigned for renewable energy credits.

Economic Drivers

MR. MARTIN: We spoke earlier briefly about the significance of tax subsidies. John Eber or Ned Hall, one of you argued that RPS standards are what is really driving the market at this point. How important are tax subsidies for solar and wind?

MR. HALL: The production tax credit provided enough of a subsidy to motivate investment when turbine prices were coming down. When you could install a project for $1,000 a kilowatt, the math worked. Today we are north of $1,500. A lot of people are quoting $1,800 a kilowatt to install a project. At that price, even the PTC is not enough to motivate the investment. In Texas, you can still do it against marginal energy. Today in some 37% capacity factor areas, even with the PTC you need $80 a megawatt hour to make the projects work.

MR. EBER: I have seen deals like in Hawaii where you don't need a PTC at all. There are projects in Hawaii where no one is claiming production tax credits because the projects are economic without the subsidy. That is an example of where the entire country may be headed. The cost of electricity in Hawaii is high because the economy is oil based. Everything must be imported. Electricity prices are among the highest in the country. Wind is economic in such a market without any subsidy.

MR. MARTIN: Let me insert another data point. Tax subsidies pay 60% of the capital cost of a solar or wind project on a present-value basis.

MR. HALL: It's probably higher.

MR. O'BRIEN: We began in Ireland, and we had spectacular success by going into our own retail business. Then we went to the UK, and we have been successful there without any subsidy. We were fortunate because we had windy sites. We believe it is possible to succeed in this business without government support. What we have recently seen is an increase in turbine prices of 20%. We believe the trick is not to think of this not just as wind farm development, but as an energy business. We look at the whole food chain all the way to the end customer. The customer is key because you need to make money from a position as a middleman.

MR. EBER: When you consider the volatility risk in fossil fuel prices, some renewables can look very attractive without the tax subsidies. In some parts of the country, people who are relying on wind and other renewables for their electricity are now paying less than they would if they had remained dependent entirely on fossil fuels. Nobody factored in the expectation that oil would hit $70 or more a barrel.

MR. RESCH: The trend is toward longer state incentives. For example, California introduced a solar initiative that is an 11-year program designed to install 3,000 megawatts of distributed PV in California. The Bush administration created a 10-year research and development program with the Solar American Initiative that focuses on ways to drive down costs and improve efficiency with solar. Two bills have been introduced in Congress to extend the residential solar credit by eight years.

We are seeing strong support for what we view as a 10-year marketplace. At the end of 10 years — in 2015 or 2016 — depending on the cost of fossil fuels and what the US government does to curtail carbon emissions, solar will be the lowest cost option for retail electricity. That is where we see things going, and now we have a lot of public policies to help us get there.

MR. MARTIN: Ned Hall, what are the wind people assuming will happen to the production tax credit? The deadline to place projects in service to qualify is the end of next year.

MR. HALL: I think everybody is operat- / continued page 12

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ALTERING THE TERMS OF A DEBT INSTRUMENT can sometimes have tax consequences.

However, the IRS ruled privately that there were no such consequences in a case where the borrower — a corporation — essentially disappeared by converting into a limited liability company that was "disregarded" for tax purposes.

Companies should exercise caution before changing the terms of an outstanding loan. Under IRS rules, after any "significant modification" of a debt instrument, the parties to the loan are treated as if they exchanged a new debt for the old one. If the "issue price" as determined for tax purposes of the "new" loan differs from the issue price of the old loan, then one of the parties to the loan will have a taxable gain and the other a loss. The hypothetical exchange of the old debt for the new one will trigger a tax on the gain.

This is unlikely to be a problem in practice unless the debt instrument is publicly traded.

Examples of a change in terms that the IRS considers significant are a change in the borrower of a recourse debt, a change in yield of more than 5%, or if greater, 25 basis points on a debt with a fixed amortization schedule, or a change in a substantial amount of the collateral and guarantees that secure a nonrecourse debt.

In the case addressed in the IRS ruling, a parent corporation issued five series of publicly-traded debentures that were essentially recourse loans to the parent. However, the holders of the debentures could exchange them for a number of shares of subsidiary or parent corporation stock.

The parent corporation merged with another company and became a subsidiary of a new parent corporation. It then converted into a limited liability company that was "disregarded" for tax purposes, meaning that it essentially disappeared. This had the effect of making the new parent corporation the obligor under the debentures for tax purposes. At the time, the debentures were trading substantially below their issue price, so there / continued page 13

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ing as though there is 100% percent probability the deadline will be extended by the end of next year.

MR. MARTIN: Rhone Resch, December next year is the deadline to put solar projects in service to qualify for a 30% investment tax credit. What odds does the solar industry place on an extension?

MR. RESCH: We think the odds of an extension by the end of next year are also almost 100%.

MR. MARTIN: Coming back to the point that John Eber made about portfolio theory, the World Bank has been very interested in a paper that an economist with the University of Manchester wrote that makes the following point. Even though renewable electricity may look more expensive at first glance, It may actually bring down the average cost of electricity when it is part of a larger portfolio. The cost of wind does not vary. There is a large risk that the cost of fossil fuel will bounce up and down.

The main way people get value for tax subsidies in the wind market, since most don't have the tax base to use them effectively, is something called a "partnership flip" structure. The IRS has now put a hold on any further private letter rulings involving such structures. Lance Markowitz, how do you think that hold has affected the market?

MR. MARKOWITZ: Flip structures have been around for a while, so I don't think anyone will stop doing such transactions. Our institution has done a number of deals without private letter rulings. In the last couple years, people have been aggressively refining flip structures. Developers would probably prefer, at the end of the day, that the equity investor have no more economic interest in the project than a lender. People doing such deals will probably think harder about how aggressive they want to be in such structures, but the market will remain open.

MR. EBER: That's a good point. The structures being used today are far more aggressive than the structures in use a couple years ago. As more potential equity investors crowd into the market, there is a natural tendency to push on bids.

MR. ROBERTSON: Our Sunny Solar Funds is a flip structure. What we see in the solar market is a lot of equipment leasing people are eyeing solar as just another asset class like trains or subway cars. We have just finished a structure in Hawaii that is a sale leaseback, and that will probably be the model for solar in most US states in the future rather than partnership flips.

MR. EBER: Solar lends itself to a lease because it qualifies for an investment tax credit. You cannot use a lease in a wind deal because the production tax credits will disappear.

Biggest Risk?

MR. MARTIN: One thing that is driving the solar market to leasing is if you use a partnership, the equity must be in the deal before the project is completed, whereas if you have a lease, the equity has three months after the project is completed to make its investment.

Let me ask one more question. What is the biggest risk to an equity investor investing in your segment of the market?

MR. RESCH: You mean other than clouds? It is certainly not technology on the solar front. PV is a rock solid technology. It has been around for 50 years. It goes up into space. It is over-engineered. It comes with a 25-year warranty for performance.

I think it might be some of the uncertainty surrounding government policies in this area. One of the big challenges for solar is trying to implement interconnection standards, net metering and time-of-use pricing. If we get time-of-use pricing as we have seen in California where they are charging 33¢ per kilowatt hour for peak power for classified users, solar is competitive well before 2015.

MR. ROBERTSON: From SunEdison's perspective, PV is a distributed generation technology predominantly today. The utilities are at odds with that because it means the utilities are able to sell fewer kilowatt hours. I think our biggest risk in a growing market depends on developing viable programs in new states. Without fail, every state has significant utility resistance to policies that benefit solar. The biggest risk is the lack of utility support for any of these RPSs that the politicians pass.

MR. MARTIN: Are the RPSs in danger of being repealed?

MR. ROBERTSON: No, but Colorado is an instructive example. The voters passed a ballot initiative requiring renewables and specifically requiring a certain amount of solar. The legislation stops there. It delegates how you do that to a public utility commission, leading to two years of rulemaking where the utilities try their darnedest to undermine the new standard. There are 15 such examples around the country.

MR. MARTIN: What is the biggest risk in the wind market for an investor?

MR. O'BRIEN: The fact that the production tax credits disappear every two years and must be renewed makes it very difficult to build a business. It introduces uncertainty in the market. I would rather see the industry weaned off the PTC over a period of time than this stop-and-start nature to the business.

MR. HALL: I share the solar view which is to ask whether the RPSs will hold. They exist, but there is not a lot of clarity or commitment to paying the price needed to sustain the renewables market.

MR. EBER: From the perspective of an equity investor, our biggest risk is achieving our economic expectations. Everybody is so busy chasing the deals, but once you get them, you find out that none of these projects performs the way it was projected to perform. Some perform better; some perform worse. Sometimes it's the wind, sometimes it's the equipment, sometimes it's the economy.

Wind projects are truly intermittent energy projects. You have to be prudent when trying to put together a portfolio of them, and then you have to live with them for 10 or 15 years. They are not what everybody expects them to be at the end of the day.

MR. MARTIN: You have 13 wind projects in your portfolio. How have they performed on average?

MR. EBER: There are actually about 18 wind farms. Of that number, we have had more than a year and a half of experience on nine of them. The nine projects are performing on average at about 94% of expectation, which would put them at what we call in the wind industry somewhere around maybe a P80 case. The best wind farms are at about 105% of expectation, and the worst are at about 85% of expectation, which is what we call a P95 case.

MR. MARTIN: That's after two years at most. Do you think over 10 years that the wind farms will perform as expected?

MR. EBER: Not on that one, no.

MR. MARKOWITZ: The biggest risk is dashed expectations. Wind farms are being marketed to some investors as an alternative to the low-income housing market. I spoke to one investor at the Global Windpower 2006 conference who invested in a wind deal and found that it is not performing as he expected. The performance has been closer to a P95 case than the P50 case on which he invested. There have been issues with the turbines. The costs are a little higher than expected. This investor came into the deal thinking the risks were on a par with the low-income / *continued page 14*

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would have been tax if there was a change in obligor.

The IRS ruled privately that there was not. It said even though the original obligor disappeared for tax purposes, it was still there as a corporate legal matter and nothing had changed for anyone but tax lawyers. It said it would look to state corporate law in such cases to see to see whether anything has changed.

The ruling is Private Letter Ruling 200630002. The IRS made the text public in late July.

Although the ruling was helpful to the taxpayer, it is a warning not to assume that "disregarded entities" are always ignored. Even though IRS regulations say that such entities are ignored for almost all tax purposes, the IRS continues to chip away at this principle in rulings.

INTEREST RATE SWAPS must be marked to market for tax purposes at year end by banks, but there is room for disagreement about how to value them.

A long-running dispute between JPMorgan Chase Bank and the Internal Revenue Service went back to the US Tax Court in August for still more proceedings.

At issue is how to value interest rate swaps that the bank entered into between 1990 and 1993. The trial before the tax court involved 28 witnesses, more than 10,000 pages of exhibits and another 3,300 pages of briefs from the parties. The judge ended up rejecting the approaches of both parties and instructing them to use a different valuation method. However, the new method proved too complicated. More than a year later, both parties came back to the court with new calculations and briefs, at which point the judge essentially gave up and issued a cursory order adopting the IRS approach.

The case may be moot. In May 2005, the IRS said in a proposed regulation that it will accept whatever value a taxpayer assigns swaps on its financial statements. However, the proposal has not been formally adopted. / *continued page 15*

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housing market; he did not do his homework. There is a whole army of people who are being sold that pitch. The biggest risk is to investors who get into a deal not realizing this is project finance 101.

MR. MARTIN: In terms of performance risk, Rhone Resch, you rely on solar electricity to light your house. How many nights have you spent in the dark?

Wind farms that have been in service for two or three years have performed at 94% of expectation or at P80 levels of output.

MR. RESCH: I am grid-connected, so none so far. Or I should say all of them were spent in the dark because I was pretty much sleeping. So far, the system has generated about 30% more electricity than we have consumed.

MR. MARTIN: So is Pepco paying *you* money?

MR. RESCH: I have a credit that I will carry over to air conditioning season that I am sure we will use up quickly. ◎

Is "Merchant" Still a Dirty Word?

Many bankers lost their jobs in the wake of the Enron collapse, and many independent power plants were put on the market. Lenders grumbled that the forecasts of energy prices on which they relied were wide of the mark and that the worst-case projections from consultants were not the worst case. Contracted assets found a ready market. Merchant plants were harder to sell. Is it really possible that only a few years later lenders are ready again to finance new merchant power plants?

Six market veterans discussed this topic at a Chadbourne conference in June. The six are Joseph Esteves, managing director for finance at LS Power Development, LLC, a leading US independent power developer, Steve Cheng, a managing director of Credit Suisse, William Sutherland, vice president of project finance for Manulife Financial, Douglas Sherman, an underwriter with CSG Investment, Inc., which is affiliated with Beal Bank, Markus Christen, a former member of senior management of Credit Suisse and now a private investor with MC Capital Partners LLC, and Charles Wilson, director of business unit finance for Duke Energy Corporation. The moderator is Rohit Chaudhry, a project finance partner in the Chadbourne office in Washington.

MR. CHAUDHRY: Steve Cheng, let me start with you. What financial structures allowed lenders to get comfortable with merchant risk in the merchant plant financings that were done in the late 1990s?

MR. CHENG: I don't think there is a difference between the structures that were used then as opposed to now. The difference is in how assets are valued today and what lenders rely on before agreeing to lend. For example, lenders were more likely in the past to accept a value for a new-build project of $600 to $700 per kilowatt. Today, they are valuing assets at a fraction of the actual construction cost. There is a big difference between lending to a project that the bank thinks is worth $600 and one that the bank is only willing to accept is worth $300 to $400 a kilowatt. The other thing that has changed is financings were done in the past based on market studies and projections. There is a much more developed and liquid market for power today than there was in the past. Lenders no longer have to rely solely on what a consultant says should happen. They can look at what the futures market itself says the power will be worth.

MR. CHAUDHRY: Doug Sherman, what did lenders expect the last time around in terms of leverage, cash sweeps and debt service coverage ratios?

MR. SHERMAN: The most common financing structure at that time was a mini-perm loan supported by a tolling agreement. Leverage in such structures was as high as 85% to 90%. Lenders were generally comfortable with interest-only-type structures and were deferring repayment of principal. Today, the market has reverted to a full cash flow-sweep type of structure. Coverage ratios remain in the 1.2 to 1.5 range.

MR. CHAUDHRY: Markus Christen, anything to add to how merchant deals were structured the last time around?

MR. CHRISTEN: A lot of the structuring is driven by perception in the market. I financed two wind farms in the late 1980s and early 1990s. No one else wanted to touch them. Today, wind farms are the darling of the banking industry. My point is everything goes in cycles. Perception in the market defines what is possible and what kind of structures you will use. Initially, only a few brave lenders are willing to do it. Next, everyone is falling over each other to do deals. Next, something blows up, people get burned, and no one wants to do it.

The phrase "merchant plant" can have various meanings. You need to dig deeper in your analysis. What risks is the lender really taking? The word "merchant" means that the project is selling into the market rather than under a long-term contract. It really matters what type of fuel the plant uses and how well developed a market there is in the area where the plant is located.

There are more hedging products today that can be employed as a risk mitigant.

It remains very difficult today to finance new combined-cycle gas-fired power plants in markets where gas is at the margin. There are too many such plants already in certain markets. Lenders will wait before taking that risk.

Lessons Learned?

MR. CHAUNDRY: I want to get a sense from each of you what you think was the main reason why the merchant plants failed the last time. I don't want an elaborate answer — just the main reason. Steve Cheng, let's start with you.

MR. CHENG: The old financings were over leveraged. The problem was too much debt and not enough economics to support the debt.

MR. ESTEVES: A number of projects suffered from too high leverage and not being able to withstand the normal types of cycles that one should expect in a commodity market. However, in projects that were the true disaster cases, people may not have done as much diligence as they should have or else they just ignored things because of all the excitement around building new generating plants. I am referring to things like transmission access and even ability to secure fuel at attractive prices. The toughest problems have been where projects literally cannot sell power so that they are not covering their fixed expenses.

MR. SUTHERLAND: I think the problem / *continued page 16*

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Section 475 of the US tax code requires securities dealers to mark to market securities that they are holding at year end, meaning determine their value and then report a gain or loss based on the change in value from the year before. (If the securities were acquired *during* the year, then the gain or loss is calculated against the price paid for them.) This rule does not apply to securities held as inventory for sale to customers. Swaps are considered securities.

JPMorgan Chase calculated its swap values by running a computer program called the Devon derivatives software system. The Devon system assumes that both parties to the swap have the same AA credit rating. JPMorgan Chase took the mid-market values generated by the computer software and adjusted them for credit risk and administrative costs to maintain the swaps. The IRS disagreed with how the bank calculated the adjustments.

In mid-August, a US appeals court sent the case back to the tax court. The appeals judge was unimpressed with the way the tax court simply gave up, but he also said the tax court had not been fair to the IRS in the first instance. Taxpayers are required by section 446 of the US tax code to account for income in a manner that clearly reflects income *"in the opinion of the [IRS]."* This makes it very difficult for anyone to challenge the IRS on an issue like the proper method to value swaps. The taxpayer cannot merely show his approach makes more sense; he must show that the approach the IRS wants to use is arbitrary or unlawful.

The case is *JPMorgan Chase & Co. v. Commissioner.*

"INVOLUNTARY CONVERSIONS" are not easy to achieve.

The IRS told a utility that was ordered by its public utility commission to divest at least half of its power plants that it could not delay reporting the gain from the sale as taxable income on grounds that the plants were "involuntarily converted" into cash. The IRS / *continued page 17*

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was too much liquidity in the financial markets leading to an over build and too much capacity. The banks just piled in.

MR. SHERMAN: The developers led the charge, and the bankers were more than happy to feed them the liquidity that they needed. There was irrational exuberance. Size mattered. For example, Calpine was out there with an announced goal of 76,000 megawatts and anybody who announced a plant would get an immediate stock market bump, with the result that everyone was vying to announce as many plants as possible in a short time period. The other problem was too great a concentration on deploying gas-fired power plants. Everyone assumed coal plants would be retired from service. Instead, such plants have been running at as high as 95% capacity factors.

MR. CHRISTEN: There was complete disregard of market fundamentals as bankers fell over themselves to win mandates. The bankers were relying on the consultants, and every consultant assumed he was working on the one merchant plant that would actually be built and all the others would be canceled. In fact, all the plants were built.

MR. CHAUDHRY: Did the lenders really take a hit in the last merchant wave or did they come out more or less whole because, when the assets were sold, the sales proceeds covered the debt?

MR. CHRISTEN: I don't think you can answer that in the abstract. Some lenders took a hit. Some equity investors bought the distressed assets and made a ton of money. The question is how nervous did a particular lender get, and when did he sell. No doubt some banks sold at 50¢ or 60¢ on the dollar. Some bankers probably lost their shirts. Others did not. Some new entrants in the market made a ton of money.

New Merchant Financings?

MR. CHAUDHRY: Using Markus Christen's definition of a merchant plant as a plant without a long-term contract, but with some form of hedge against price risk, are lenders starting to do merchant deals again? Doug Sherman?

MR. SHERMAN: Anyone who has entered into a term B structure where there is a hedge with Morgan Stanley or Goldman Sachs is effectively taking merchant risk on the back end. In all of these structures, there is a sweep of 100% of cash flow. However, in the event there is not enough cash to repay the loan and the hedge runs out, the lender will be exposed to a plant that has reverted to pure merchant status.

At CSG, we will take merchant risk, but based on an analysis of the core value of the project as a merchant plant. We strip it down. We focus on how the plant will behave on a merit-order-dispatch basis at a specific site. We look at all the locational factors, gas price, the ages of competing plants, and the shape of the capital structure.

MR. CHAUDHRY: Steve Cheng, do you see many lenders today who are willing to finance a new power plant on a purely merchant basis without a hedge?

MR. CHENG: People are looking at it. The only deal to date that I know of that was done as a merchant plant right out of the box was the restructuring that Credit Suisse did for Boston Generating. There were no financial hedges. Boston Generating had the benefit of a couple reliability-must-run contracts that provided a foundation for revenue stability, but — as a percentage of total revenue — the must-run output was a small percentage. At some point, a purely merchant deal will get done, but all the deals that have been done in the last year to 18 months have employed some type and some amount of hedging: financial hedging, tolling agreements or power purchase agreements. At some point, there will be another purely merchant deal.

MR. CHAUDHRY: To get a sense of the size of the market, how many deals have you seen in the last 18 months that fit Markus Christen's definition of merchant — no power purchase agreement but with a hedge?

MR. CHENG: There have been more than a dozen such deals.

MR. CHAUDHRY: How many do you expect in the next year or two?

MR. CHENG: I expect about the same number.

MR. CHAUNDRY: Joe Esteves, are there particular markets in the United States where it should be easier to finance a merchant plant without a hedge?

MR. ESTEVES: LS Power just closed a financing where we put a hedge in place right before closing, but we had a financing commitment to close without the hedge. If the question is whether projects can be financed on a purely merchant basis without a hedge, then our experience demonstrates that they can.

Lenders are a lot more cautious about the value they place on a plant. They are no longer relying solely on forecasts as was mentioned earlier. Someone said the market is relying less on consultants. The truth is there are more roles today for consultants because now you need a commodity hedge consultant and the bankers need a valuation expert.

It helps that the markets are more transparent today. A lender can look at where prices are trading several years out. Even if the project is not signing a contract today to sell the output, there is a sense that it could sell at the future prices if it wanted. As markets become more liquid, there will be less need for hedges.

Key Distinctions

MR. CHAUDHRY: Markus Christen, do you want to add to that?

MR. CHRISTEN: I think it is important to ask what kind of deals are being done today on a merchant or quasi-merchant basis. They tend to be acquisitions of existing assets rather than greenfield projects. Would anyone finance a new gas-fired power plant on a merchant basis? The answer is probably no.

MR. CHAUDHRY: Why is there a distinction between acquisition financing and greenfield financing? Is it because existing assets are trading at a discount to cost?

MR. CHRISTEN: Yes, that is a big factor.

MR. CHAUDHRY: Bill Sutherland, you have been working on wind farms. Do you see a difference between doing a merchant wind deal versus a thermal deal?

MR. SUTHERLAND: In fact, we did a merchant wind deal last December, closing a completely exposed, unhedged project in Alberta, and we gained comfort in that because a wind farm, unlike a gas plant, has a very low operating cost. It is dispatched in all events. It has a profit margin under pretty well any conceivable market price scenario. There are few lenders actually looking at merchant wind, with the result that we have been able to be conservative in the amount of leverage put into such transactions. The point is there are opportunities for lenders to finance merchant plants today in the wind sector.

MR. CHRISTEN: To second that, we are doing a merchant wind deal in Texas right now.

MR. CHAUDHRY: What type of leverage is on offer typically in a merchant wind deal?

MR. SUTHERLAND: It depends on the capacity factor that a particular wind farm is expected to achieve. Projects in some of the better wind regimes can achieve much higher leverage than the projects in other locations. It also depends on the market into which the project will sell. The leverage in the Alberta project was 40%.

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reported its conclusions in "technical advice memorandum." A "technical advice memorandum" is a ruling by the national office to settle a dispute arising in an audit.

A company does not have to report gain on assets that it is forced by government action to convert into cash as long as the company reinvests the sales proceeds within two years in replacement property that is "similar or related in service or use" to the property that was converted. The IRS said the utility in this case failed to prove that its assets were involuntarily converted.

The IRS said it will rarely accept that assets were involuntarily converted unless they were taken directly by the government The government sometimes orders companies to divest assets due to anti-trust concerns or to limit the use of property because of health, safety or zoning concerns. These are normal uses of government police powers and are not a "taking" of property by the government, the IRS said. It said there would be a "taking" in such cases only if a company is denied "all economically beneficial uses" of the assets, adding, "One who does business in a regulated field cannot reasonably rely on the status quo because there is the foreseeable potential for regulatory change."

The IRS said that even if the assets had been involuntarily converted, the utility failed to show that it reinvested the cash in replacement property.

The utility filed amended tax returns reporting after the fact that its assets were involuntarily converted. It argued that the sales proceeds were reinvested in normal spending on upkeep of other assets and other investments the utility made within the two years in its business. The IRS said the replacement property must be acquired with the specific intention to replace the assets converted. Therefore, one cannot designate an asset as replacement property after it has already been purchased.

The ruling also addressed whether utilities that turn operational control of their electricity grids over to a regional trans- */ continued page 19*

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MR. CHAUDHRY: Doug Sherman, you said you will be willing to look at purely merchant deals. What kind of leverage do you think such a project can achieve?

MR. SHERMAN: Somewhere between 50% and 70% for the right thermal power plant and a little less for a wind farm. Like Bill Sutherland, we put out a term sheet on a merchant wind deal. This one was in the United States.

MR. CHAUDHRY: How do you get comfortable that problems like overcapacity that were the downfall of many merchant plants the last time around will not repeat this time?

MR. SHERMAN: We take a conservative approach. We look at the mean-reverting gas prices. We spend considerable time on a discounted cash flow analysis. We look at where the plant is in terms of system-wide heat rates. We look at comparable sales prices for where similar assets are trading in the market in addition to the cash flow analysis.

MR. CHAUDHRY: Joe Esteves, you spent a lot of time this year on financing the Plum Point project, a large greenfield coal-fired power plant in Arkansas. If I am not mistaken, Plum Point had no offtake contracts when the financing closed. Can you talk about how that deal was structured?

Hedges

MR. ESTEVES: It is probably not the simplest structure that the market has seen. We think there is an important timing advantage to getting to market soon. We are once again in a building boom. Everyone is talking about coal just like everyone was talking about gas earlier. It was important to get started quickly on construction and not wait until the plant was fully contracted.

Having the plant under construction also helps with potential offtakers. It can be challenging to persuade someone to sign a long-term contract when you are talking about a wait of another four years before the plant is ready to start generating electricity. Offtakers suspect that other options may become available in the meantime, and they would rather wait to see what develops. It is more difficult today to have everything secured in advance.

Turning to our financing structure, most of the potential offtakers for the electricity from Plum Point were municipal utilities and electric cooperatives. We ended up selling about 37% of the plant capacity to two muni groups and a coop. The project is 665 megawatts. We had long-term contracts for about 100 megawatts, and the rest was essentially merchant. We needed to do something to assure the lenders that there would be stable revenue for at least some period of time.

We also ended up putting in place options on gas to hedge a coal unit, which was interesting. There were a number of hedging alternatives available — everything from short-term physical sales to financial deals on electricity. We ended up with a hedge on gas because it was very important to us to be able to unwind in a transparent fashion. We expect to sign long-term contracts to sell electricity immediately after construction. We wanted to make sure we could unwind the hedge without taking a big economic hit. The bid-ask spread in some types of hedges can be wide. Gas hedges trade in a more liquid market than electricity hedges. Thus, for both unwind reasons and bid-ask spread reasons, we ended up with put options on gas.

MR. CHAUDHRY: Could you give a brief explanation for the audience of what a financial hedge is?

MR. ESTEVES: I think they come in different varieties, but the ones that seem to be most prevalent in the last few deals that were done come in the form of heat rate coal options. Think of it as a traditional call option on any type of commodity. In this case, the strike price on the option is set up to mirror the true cost of running the power plant. Thus, in essence, the buyer of the call option is looking for opportunities where market prices of electricity exceed the strike price or exceed the operating cost of the unit.

There are several institutions that are willing to act as counterparties in such hedges, including Credit Suisse, J. Aron

About a dozen power projects have been financed in the last 18 months on a quasi-merchant basis, meaning without power contracts but with electricity price hedges.

and Morgan Stanley. Everyone is taking a page from the derivatives that already exist in other commodity markets and applying the same learning to this market.

It is important that the hedge be one that settles financially rather than through physical delivery. As you might imagine, there are lots of nuances. In an ideal world, you try to mimic the true cost of the facility by taking a specified heat rate and perhaps an indexed gas price. If you can't secure gas at that index or if you are not actually selling electricity from your plant at the electricity index on which the call you sold is based, then you are not perfectly hedged, but you may be able to satisfy yourself that it is a manageable risk.

You can you write contracts on anything. For example, you can set up a contract that says the counterparty to the hedge will pay the developer the price at X hub to the extent it exceeds a specified heat rate times an indexed gas price.

MR. CHAUDHRY: Bill Sutherland, are people talking about hedge products in wind deals as well?

MR. SUTHERLAND: There have been several done recently with hedges on them. Hedges must be structured in a manner that takes into account the variability of the wind resource. We typically characterize the resource base case as a P50 case, meaning that there is an equal chance the project will generate more or less electricity than has been projected.

Hedges typically are based on a P95 or P99 output case. In a P99 case, there is only a 1% chance that the project will underperform. That means there is assured production to meet the requirements under the hedge, and the balance of production remains unhedged. However, when you take into account that production tax credits are essentially a contracted revenue source, and there may also be a contract to sell renewable energy credits from the project at fixed prices, these contracted sources of revenue plus the hedge leave little real market exposure.

MR. CHAUDHRY: Doug Sherman, what is the typical term for a hedge?

MR. SHERMAN: Most of the hedges I have seen run five years in duration.

MR. CHAUDHRY: And how does this then affect the structure for the project debt?

MR. SHERMAN: In some cases, lenders have tried to match the term of the debt to the hedge and have a sweep of 100% of cash flow. In other cases, I have seen two years of excess debt beyond the hedge period — for example, a 7-year loan based on a 5-year hedge. As I noted earlier, / continued page 20

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mission organization under government orders suffer an involuntarily conversion of their grids. The IRS said no. It said that the government has merely changed the form of regulation over the grid. The utility has always been required to use its grid to serve customers. Now federal regulators have expanded the customer base to include competitors, like independent generators, who want to move power over the grid.

Finally, the agency also rejected the claim that stranded-cost rate recovery orders are compensation for an involuntary taking of property.

Utilities have historically had a monopoly right to supply electricity in a designated service territory. Many states have moved to deregulate their electricity markets. The retail supply of electricity remains regulated, but some states offer consumers the right to choose among competing electricity suppliers. The wholesale market for electricity is usually fully deregulated. Utilities that built new power plants with the expectation that they would be able to recover the cost in rates over time were caught with declining customer bases to whom they could charge the last of these power plants. States often let utilities recover these "stranded costs" over a fixed number of years by assessing surcharges on electricity or wheeling rates. Many utilities have borrowed against the stranded cost orders, thereby converting the additional revenue they expect to collect over time into immediate cash.

The IRS refused to accept the characterization of the stranded cost recoveries as compensation for an involuntary taking of property (the monopoly franchise over a service territory). It said they are simply a speeding up of what the utility would have collected anyway through rates. "The ratepayers did not view the payments of [stranded cost surcharges] as compensation for a government taking because the charge had always been a part of the ratepayer's rate."

The ruling is Technical Advice Memorandum 200627024. The IRS made it public in early August. / continued page 21

Merchant Plants

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the lender is still taking merchant risk for the period after the hedge expires.

MR. CHAUDHRY: So lenders are generally taking two years of merchant risk. What do these hedge products generally do for the leverage in a deal? How much more debt can a developer hope to secure with a hedge than if his plant is financed on a purely merchant basis?

MR. SHERMAN: In some cases where we have looked at a plant on a purely merchant basis, we may be able to get to 70% or 75% leverage. In some of the hedged projects, I have seen leverage go as high as 80% to 85%. So I would say that a hedge allows for as much as 10% additional leverage.

MR. CHAUDHRY: Do others on the panel agree with the 20% figure? (The other panelists nodded their heads affirmatively.) Charlie Wilson from Duke, I believe you have a comment?

Plus Ça Change?

MR. WILSON: Thanks for putting me on the spot. I think you have to ask the question Markus Christen asked earlier. When you use the word "merchant," be clear what it is you are talking about. Is it a purely merchant plant or is there some financial hedging involved? The ability to put hedges in place that absorb market risk is extremely limited. Are there tolling agreements? People sometimes lose sight in such deals that what they are really doing is converting commodity risk into credit risk. Projects that had tolling agreements with Williams and Enron turned out to be unhedged in practice.

What went wrong the last time is a complicated litany: too much liquidity from the financial markets, inaccurate projections of electricity demand, stillborn deregulation, lack of uniformity in terms of the market models state by state, poor market design in places like California, and lack of capacity markets.

There was an illusion the last time around of a liquid trading market. Enron, when it existed, made everyone think that there was a very deep and liquid market to hedge commodity risk because Enron was able to conceal the fact that it was just recycling and circling and nothing was really getting done at the end of the day. When Enron collapsed, people, like Duke, who had built their merchant models on the same basis, which was largely a trading-centric model, found out there was inadequate financial liquidity.

Power is not like other commodities like oil and metals. Yet that was the basis for this whole trading-centric idea — the view that you can more efficiently hedge at a large portfolio level with a large trading organization that trades in a very deep market. This ignores the fact that electricity is locational. You can't get to the model on which the earlier boom was based when you don't have a uniform market structure.

PJM is a good example. You have literally 1,200 different pricing locations. It is impossible for Wall Street to come up with a way to generate enough liquidity at each pricing point to allow adequate hedging. People use the gas market analog; gas has enough history and liquidity that it allows people to trade around particular nodes relatively efficiently. However, this is not the case with power, and it may never be the case with power.

My advice is don't get caught up in the euphoria of the private equity and highly-leveraged transaction folks. To us, that is a short-term, opportunistic financing model. It has been driven by depressed asset values. It has been driven by the extraordinary liquidity that shifted into the market from hedge funds and private equity looking for ways to invest the extraordinary amount of capital they have amassed.

We think those people will make money, probably a lot of money, on the assets we and others have sold them, but we do not think that is a sustainable model for the next round. Those guys are not going to own those plants for very long. My view is the next time around, it will be back to the future. You will see more inside-the-fence plants. Plants in regions with active capacity markets will be easier to finance.

MR. CHAUDHRY: I was planning to end with your comments, Charlie Wilson, but I want to turn back to Joe Esteves and ask whether he disagrees with anything that was just said.

MR. ESTEVES: I think the only thing I disagree with is the implication that he was ill-prepared and put on the spot. [Laughter.] ⊚

DOE Releases Guidelines for Loan Guarantees

by Luis Torres, in Washington

New guidelines released by the US Department of Energy in mid-August explain when the US government is prepared to guarantee repayment of commercial debt in energy projects.

Congress authorized the Department of Energy to guarantee such debt in the Energy Policy Act in August 2005 for a variety of energy projects.

The new guidelines only apply to the first round of loan guarantees to be issued under the program. Total guarantee commitments in the first round will not exceed $2 billion. The first round will only cover guarantees under title XVII of the Energy Policy Act, which deals with projects that use innovative technologies.

The deadline to apply for guarantees during the first round is November 6.

The department will review the applications it receives, but it will not be able to issue any actual guarantees without an appropriation from Congress. The appropriation is needed to cover administrative costs of the program. Borrowers will be required to pay fees to cover any subsidies they receive.

Eligible Projects

Ten categories of projects qualify potentially for guarantees in the first round. They are listed in the chart on the next page. Congress also authorized guarantees for nuclear and oil refinery projects, but they will be the subject of a future round of solicitations.

The new guidelines only answer some questions. The default rules and audit requirements will be addressed in separate regulations.

Substantive Insights

The department said it plans only to guarantee debt on projects with technologies that are mature enough to generate sufficient revenues once the project begins commercial operations. The rationale is that the more tested or mature the technology is, the greater the chances of repayment of the guaranteed loan.

This is sure to disappoint developers who were hoping the loan guarantee program would help projects that are having trouble borrowing in the private sector because banks do not want to take risk on newer technologies that have not been proven yet on a commercial scale. It is not clear the US government is prepared to take technology risk, either. The guidelines make clear the government will not guarantee debt on technologies that are still in the research and development or pilot phase.

Congress limited the amount of the / continued page 22

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FOREIGN TAX CREDIT STRATEGIES took a hit in proposed regulations the IRS issued in early August.

Some US companies with business operations outside the United States should revisit their offshore ownership structures.

The United States taxes US companies on their worldwide earnings, but allows them a credit for any income taxes paid to other countries. The credits are ordinarily taken when the foreign earnings are repatriated to the United States.

However, the timing of when foreign tax credits can be claimed can become complicated when a US company has multiple foreign subsidiaries and some of them are treated as a consolidated or combined group for tax purposes in a foreign country. In that case, the US looks to the foreign country law to determine where in the ownership chain the tax is imposed. If the tax is imposed legally on the offshore parent company of the combined group, it is arguably possible to claim foreign tax credits for the taxes imposed on the parent immediately in the United States while shielding the earnings from US tax by trapping them at least one tier down in the other subsidiaries in the group. This would be done, for example, by treating the parent company as a "disregarded entity" for US tax purposes, while treating the subsidiaries as corporations.

The IRS is troubled by such arrangements. It believes taxes should not be credited in the United States until the related earnings also become subject to US taxes.

The proposed regulations address when foreign tax credits can be claimed in situations where offshore consolidated groups, hybrid entities and reverse hybrid entities are involved.

A "hybrid entity" is a company that is treated as transparent for US tax purposes but as a corporation in another country. In other words, the other country treats the entity as subject to tax directly. The United States views any such taxes as imposed on the owners rather than the hybrid entity. The IRS said / continued page 23

Loan Guarantees

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guarantees to 80% of "project costs" without defining what costs qualify as project costs. The guidelines define "project costs" as costs that are "necessary, reasonable and directly related to the design, construction, and startup of a project." Project costs include costs for the purchase of land and equipment as well as engineering, legal and other professional fees. Spending on research and development, post-construction operating costs, and fees paid to the US government to secure a loan guarantee do not qualify as project costs.

Any other debt on the project beyond the amount the US government guarantees must be subordinated to the guaranteed debt.

Each project that applies for a guarantee will be subject to

List of Eligible Projects

Category	Project Types (non-exclusive)
Biomass	a) Integrated biorefinery projects based on ligno-cellulosic or plant feedstock b) Biofuels production, distribution and infrastructure
Hydrogen	a) Hydrogen and fuel cell manufacturing b) Hydrogen energy systems
Solar	a) Centralized solar electric generating facilities b) Solar technology manufacturing facilities c) Large-scale solar installations
Wind & Hydropower	a) Advanced wind power plants b) Wind or renewables specific transmission lines c) Turbine or component manufacturing d) Testing facilities for commercial wind turbine components e) Community wind power systems f) Hydrokinetic energy devices g) Hydropower technology devices in existing impoundments
Fossil Energy Coal	a) Coal-to-Fischer-Tropsch (FT) liquids b) Integrated gasification combined cycle c) Industrial gasification
Carbon Sequestration Practices and Technologies	
Efficient Electricity Transmission and Delivery and Energy Reliability	a) Advanced control, sensing and monitoring systems b) Advanced switching, transformer and substation equipment c) Distributive on-site energy systems involving critical infrastructure
Alternative Fuel Vehicles	a) Hybrid vehicles or component manufacturing
Industrial Energy Efficiency Projects	a) Private sector facilities only
Pollution Control Equipment	

a review under the National Environmental Policy Act. Such reviews can take four to six months (longer if studies are required to evaluate four seasons of data). Reviews can be costly and may make a project vulnerable to citizen challenges by project opponents.

The fact that a project also qualifies for other forms of government assistance will not prevent it from receiving a loan guarantee, but the Department of Energy will want to know the sponsor has enough of his or her own equity invested to be fully committed to the project.

In a further blow to developers who were hoping the US government would take technology risk, the Department of Energy is insisting on first position on any recovery on the project in the event there is a loss. For example, if the Department of Energy guarantees 50% of the debt on a project, it will expect any repayment by the borrower that falls short of the full amount owed to be applied first against the guaranteed portion of the debt before it is applied against the non-guaranteed portion.

From the government's perspective, this approach makes sense. It lacks the resources to do a full evaluation of project risk. Its approach creates an incentive for lenders to be careful in their choosing of projects and not make the government bear all of the responsibility for projects that are poorly planned or managed. On the other hand, the guarantees are supposed to be a way for the government to help developers get financing for projects that use new technologies. Instead, the government is forcing the lenders to take risk ahead of it. The program may not have its intended effect.

The Department of Energy describes the 80% loan cap as a "preference" and says it is willing to take a larger stake (but not 100%) as long as there is "sufficient evidence" to believe the project can support more debt. The guidelines do not give any insight as to what "sufficient evidence" is.

Commercial lenders usually expect guarantees to be unconditional come "hell or high water." That is, lenders expect a guarantor to pay if the borrower does not pay on time. Any conditions on the guarantor's duty to pay make a guarantee less attractive. Under the new guidelines, lenders must take on some tasks such as making annual reports to the Department of Energy, but the guidelines do not say what would happen if a lender fails on any of these tasks. If the DOE conditions payment of its guarantee on these requirements, it would make the guarantee program less attractive to the market..

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it would continue to treat the taxes as imposed on the owner. If the hybrid entity is a partnership for US tax purposes, then the taxes will be treated as borne by the partners in the ratio directed by US partnership rules.

A "reverse hybrid entity" is a company that the United States treats like a corporation, but a foreign country treats it as transparent. Since the foreign country does not view the company as subject to tax directly, but rather imposes taxes on the owners, the IRS said it will attribute the taxes paid by the owners to the company. Thus, for example, if a company has three owners, one must figure out what foreign taxes had to be paid by the owners on their shares of company earnings. The company will be treated as if it paid those taxes directly. As a consequence, the taxes cannot be claimed as a foreign tax credit in the United States until earnings trapped in the company become subject to US tax through repatriation. The owners will be treated in the meantime as having made capital contributions to the company for any foreign taxes they paid.

Turning to offshore consolidated groups, the IRS said it will define such groups broadly to include cases not only where a group of companies joins in filing a tax return and each of the group members is "jointly and severally" liable for the full tax shown on the group return, but also where only one of the companies — for example, the group parent — is liable for the full tax and the subsidiaries are not, and where the subsidiaries are ignored in a foreign country because they are treated as mere branches — or offices — of the parent company.

The IRS does not care which type of group is involved. It said it would require the foreign taxes paid by the group to be apportioned among all the companies in the group in the ratio of the net income that each contributes to the group return. The net income for this purpose is computed as defined under foreign law.

This approach has a number of consequences. For example, it means that foreign tax credits considered lodged in a */ continued page 25*

Loan Guarantees

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The guidelines require that both the guaranteed and non-guaranteed tranches of a loan must be traded together in secondary markets. In project finance, lenders that originally acquire a portion of a loan facility often resell it later in the secondary market. The DOE loan facilities will have a DOE-guaranteed portion and a non-guaranteed portion. A lender cannot resell just the guaranteed portion. The guidelines do not explain what happens if this condition is breached, but it could lead to inability to enforce the guarantee.

Unanswered Questions

Many questions remain unanswered about how the new program will work.

Projects must meet two basic requirements to qualify for loan guarantees under title XVII: they must avoid, reduce or sequester pollutants and gases, and they must use new or significantly-improved technologies when compared to technologies in general use in the market. The guidelines provide no details on these requirements.

The guidelines emphasize that the Department of Energy will consider the sponsors' financial commitment to a project, including the amount of equity the sponsors are contributing and the extent of risk sharing, but they provide no further insight — for example, whether equity of at least 20% of project cost is required to secure a guarantee.

Some questions relating to project completion and viability also remain unanswered. For example, the guidelines request applicants to provide details about construction contracts, liquidated damages and performance bonds, but there is no indication what level of liquidated damages will be required. The guidelines are also silent on whether the government is willing to take merchant risk.

Congress has not appropriated any monies to cover losses if the government ends up having to pay on a guarantee. Therefore, the department is expecting applicants whose projects are guaranteed to pay the full costs of the program. No detailed guidance has been provided on the calculation of such costs.

The actual loan guarantee agreement that the Department of Energy plans to use has not been released yet. It is probably a good bet that the agreement will look similar to other loan guarantee agreements used by the US government, but the market would benefit from an early look at the agreement.

Applications Process

Applying for a guarantee is a five-step process. First, the applicant must submit a "pre-application" with his or her project proposal. The guidelines list the information that the government expects to see at this stage. Pre-applications are due on November 6. Within 90 days after the November 6 deadline, DOE will invite short-listed pre-applicants to submit a more comprehensive application. Others will be notified why their applications were not selected.

The department is not charging fees for the pre-application round, but it expects to charge an administrative expenses fee and a loan guarantee fee at later stages of the process. The amount of such fees has not yet been determined.

A DOE credit committee will review the applications. The committee is expected to include the department's chief financial officer and the director of the loan guarantee program. If an application is approved, then the DOE will issue a term sheet with the terms of the loan guarantee. Once the parties agree on the term sheet, the terms will be reduced to a formal agreement. The Department of Energy will need approval from the US Treasury before actually executing the guarantee. ◎

New Technologies to Displace Oil: Are They Financeable?

The threats by Iran to build nuclear weapons, the deteriorating security situation in Iraq, the hostilities in Lebanon and the rebel attacks against oil installations in Nigeria are contributing to skyrocketing oil prices. New York Times columnist Tom Friedman predicts that if oil hits $100 a barrel, there will be a rapid demand response in the United States. Many companies are not waiting for $100 oil to act. They are already hard at work on coal gasification and coal-to-liquids plants, new ways to tap tar sands and other technologies that will eventually reduce demand for oil. Are these projects financeable and are they likely to have a major impact?

A panel discussed this topic at a Chadbourne conference in

June. The speakers are Steven Greenwald, a managing director with Credit Suisse, Dr. Robert Kelly, a former Enron executive who is now a principal with coal-to-liquids developer DKRW, Merrick Kerr, executive vice president and chief financial officer of Rentech, another coal-to-liquids developer, Tom Shelby, senior vice president for oil and gas at Kiewit, and Yoram Bronicki, chief operating officer of Ormat Technologies. The moderator is Todd Alexander from the Chadbourne New York office.

MR. ALEXANDER: Tom Shelby, there is talk today about long-term shortages of oil. Should we be worried?

MR. SHELBY: There is a smaller margin in oil supply today compared to demand, but is there a long-term shortage of oil? As long as oil prices remain high, the market will respond by looking for alternatives. The alternatives include LNG imports and increased recoveries from oil sands. As long as oil remains at $70 a barrel, people will look hard for alternatives. Even $40 a barrel provides a powerful incentive to find alternatives.

DR. KELLY: Oil demand has finally caught up with supply. There used to be a lot more slack in the system. That slack is gone. From a geological perspective, I think the oil is there. The real instability is in the political arena — in places like Iran, Bolivia and Venezuela. That dynamic is as much to blame for tightening oil supplies as geology. It is making the oil majors think harder about the risk of exploring for new supplies offshore in the Middle East and South America.

Oil Prices

MR. ALEXANDER: Steve Greenwald, it seems fairly well accepted that we are in for a period of higher oil prices. How does this play out in the deals that cross your desk?

MR. GREENWALD: It is reflected in the mix of deals we see today. We are seeing everything from IGCC plants to coal-to-liquids projects. It plays out in the fact that I am flanked on this panel by two coal-to-liquids developers. However, the real issue is investors are not willing to bet that oil will remain at $70 a barrel or even at $50 a barrel. That is the real challenge for these new technologies. There will not be a lot of private capital to develop new technologies until investors conclude oil prices will remain high in the longer term.

The banks are assuming oil will fall to the low $20 range per barrel in the downside cases they are running for current loans. One of the more recent price decks we saw for a rating agency assumed $18 a barrel long term. The rating agencies have been remarkably inconsistent. We */ continued page 26*

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subsidiary cannot be claimed in the United States until the earnings in the subsidiary are repatriated to the United States. It also means that if the group parent actually pays the foreign taxes for the entire group, it will be treated as having made capital contributions in the amount of the taxes to each subsidiary for whom it paid taxes.

The IRS is proposing to have the new rules apply to foreign taxes paid or accrued starting next January 1.

Foreign tax credits are also manipulated through use of hybrid instruments and disregarded payments. An example of a hybrid instrument is an investment that the United States treats as an equity investment while a foreign country classifies it as debt. An example of a disregarded payment is where a parent company lends money to a subsidiary in another country, but the parent chooses to treat the subsidiary as a "disregarded entity" for US tax purposes — in other words, to behave as if the subsidiary does not exist. That means that any payments between the parent and subsidiary do not exist either.

The IRS said it hopes to tackle use of hybrid instruments and disregarded payments later this year.

Ironically, the Clinton administration tried to block use of hybrid entities as a tool for deferring US taxes on offshore earnings, but its efforts were blocked by Congress. Congress has been silent about the Bush administration efforts to block use of the same tools to increase foreign tax credits.

FIN 48 will require corporations to indicate in their financial statements which of their tax positions may be challenged on audit.

The Financial Accounting Standards Board has been concerned that corporations lack objective rules for reporting tax benefits and potential exposure to additional taxes in their financial statements. The board issued an interpretation — called FIN 48 — of its rules in this area on July 13.

FIN 48 will require a company's tax department to evaluate every position the company has taken on a return using a */ continued page 27*

New Technologies

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have seen BB-rated projects at about a $30 break-even point. Then you can ask whether particular projects are economic at $30 a barrel or whether they require an oil price that is higher than that. Banks do not appear willing to bet on projects that require oil prices to remain at $30 a barrel or higher. I am not talking about 2006 or 2007 oil prices, but prices over the next five to 10 years. I am working currently with an oil major on a project in Nigeria, and we are running cases at $30 a barrel flat, and I think we are being aggressive.

MR. ALEXANDER: Merrick Kerr, Steve Greenwald has probably just explained why the oil majors are not all over coal-to-liquids. What oil prices do such projects require to be economic?

MR. KERR: The reason the majors assume that oil prices will fall is that oil costs a lot less per barrel to produce than the price at which it is selling in the current market. Another factor to keep in mind is the world seems to be working fine with oil at $50 a barrel. The economy seems to have absorbed the shock and is still growing. When you have oil supply controlled by a small number of people, there is no reason for them to let the price fall back to $15 or $20 a barrel. That's the counterargument for why oil prices will remain high.

Turning to the coal-to-liquids process, the first phase is gasification. You take the coal, convert it into a synthetic gas. It then runs through the Fischer-Tropsch process, which was developed by the Germans for the war effort when they had no access to oil. It was then further developed and commercialized by SASOL in South Africa during apartheid when they had no access to world oil. Today, SASOL produces about 180,000 barrels a day.

In terms of the economics, the process probably breaks even and makes a small return somewhere around $40 a barrel.

Coal reserves in the United States are huge. If you use just 5% of US coal to make liquid fuel with the Rentech Fischer-Tropsch process, it would be equivalent to doubling US oil reserves. That is a staggering statistic.

MR. ALEXANDER: Bob Kelly, is this the right time for coal-to-liquids given what we have heard about long-term oil prices?

DR. KELLY: Steve Greenwald is exactly right. Oil was $10 a barrel in 1997. Until the view in the market changes about where oil prices are likely to be long term, we will face resistance in the market to financing coal-to-liquids projects. The fact is the majors are finding less and less new oil. The bet that Rentech and we are making is that the market will understand the technology and operating risk. We are where tar sands projects were 10 or 20 years ago. The market got comfortable enough to finance them.

There will not be a lot of private capital to develop new technologies until investors conclude that oil prices will remain high in the longer term.

Our view is the market will get comfortable sooner rather than later. That's why we are working steadily on our Medicine Bow project, which has a capacity to produce 11,000 barrels a day of coal liquids. We expect to go to financing next year. We will have to take care of the oil price risk by hedging. How do you do that? Some people are looking at the US Department of Defense. We are not particularly interested in that. There are all kinds of hedging instruments on Wall Street to hedge financial risks.

Even though the price deck is $25 or $30 a barrel, you can put option hedges on oil for $40, $50 or $60 a barrel. The issue is who is going to profit if oil prices prove different than expected.

Tar Sands

MR. ALEXANDER: Yoram Bronicki, we keep hearing the phrase oil sands or tar sands. You have been focusing on tar sands projects in Canada. How do they fit into the larger energy equation?

MR. BRONICKI: There are two major types of production in the tar sands in Canada. The one that started in the mid-1960s is basically mining a sand oil layer and then separating the oil from the sand. This is labor intensive, equipment intensive and somewhat energy intensive. It is simple separation. And because of the characteristics of the oil and the fact that most refineries cannot digest a big diet of that oil, there is some kind of upgrading that is done on site. Output in Canada is between 400,000 and 500,000 barrels a day.

MR. ALEXANDER: Do you know how many barrels of oil the US consumes a day?

MR. BRONICKI: About 20 million barrels.

The newer tar sands projects use *in situ* combustion, which is done mostly by injecting steam into the reservoir, lowering the viscosity of the oil, and then bringing the oil to the surface. This is energy intensive, but it is not as intensive in terms of equipment and labor. These newer projects produce 250,000 to 300,000 barrels a day. This product must also be upgraded either on site or in the Alberta refineries because it is very difficult to transport otherwise.

MR. ALEXANDER: What oil price do the tar sands producers need in order for their projects to make sense economically?

MR. BRONICKI: Some of the producers have been making money, although the capital recovery was done with the help of grants. If one ignores the sunk capital, I believe they have been making money with oil around $18 a barrel. Other projects can function with $25 oil. Of course, as the oil price increases, all projects do much better.

MR. ALEXANDER: Tom Shelby, what has been your experience with tar sands? I know Kiewit opened an office in Calgary before most people had even heard the term tar sands.

MR. SHELBY: I wouldn't go quite that far. Suncor has been recovering oil from tar sands or oil sands in Canada since 1965 or 1968, something around that time frame. There have been periodic spurts in activity. We opened an office there a few years ago after concluding that the market was likely to see explosive growth. The Calgary office was opened specifically to target oil sands. Before that, we had been working off and on with such projects, but from our other offices.

MR. ALEXANDER: What is the future for tar sands?

MR. SHELBY: We are expecting intense activity for at least the next 10 years. Any forecast is a bet on oil prices. At the moment, prices are through the roof. There is a real labor shortage. We are expecting $10 to $15 billion a year to be invested in oil sands for the next 10 years. The oil is capital intensive to recover, but it is a good market because it is politically stable.

Technology Risk

MR. ALEXANDER: Let me ask you about another area where I know you have experience — gasification. How much potential does Kiewit see for substituting other hydrocarbons for oil using gasification?

MR. SHELBY: We are seeing a lot of interest in gasification not only from the regulated utilities, but / continued page 28

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two-step process. The first step is to assess whether benefits shown on the return can be booked. Only tax positions that are more likely than not to be upheld on audit can be booked. Tax positions that pass muster under this test must then be further evaluated and a probability assigned to their being upheld on audit. Tax benefits that are less than certain cannot be fully booked. The portion considered an unrecognized tax benefit will show up in most cases as a potential tax liability.

If over time, as a company's assessment of risk changes, then a later adjustment will have to be made to the amount of benefit booked.

The new rules take effect in corporate fiscal years starting after December 15, 2006. Thus, companies that use the calendar year for financial reporting will have to comply starting in 2007. However, Staff Accounting Bulletin 74 will require public companies to disclose the expected financial impact of FIN 48 as early as the Form 10-Q filed with the US Securities and Exchange Commission for the second quarter of 2006.

Critics charge that FIN 48 will provide a roadmap to the IRS about where to probe on audit.

It may also force companies to ask for more outside tax opinions because of concerns about the potential exposure under US securities laws for misstatements on financial reports. As shown in the Enron and other recent trials, the penalties can be severe.

A RATE INCREASE that was later rejected led to more taxable income than a utility wanted.

A utility was organized as a parent holding company with five subsidiaries. One of the subsidiaries produced electricity, gas or water that it sold at regulated rates to the other four subsidiaries. The other four were distribution companies whose rates charged to customers were also regulated.

The subsidiary that produced the product received provisional authority to increase the rates it charged its affiliates, subject to a possible refund after the public / continued page 29

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also from independent power producers. However, while people are willing to spend some money, they are not necessarily willing to spend the money that it takes to get a job across the finish line.

Everybody is interested in gasification, whether it is IGCC or coal-to-liquids. The Department of Energy is pushing to make jet fuel made from coal. We see a lot of interest, but not yet a clear path to finance such projects to allow them to start construction. Financiers are still asking for a huge risk premium even though the projects involve a known technology that has been in use since World War II. The problem is one of scale. There is risk in scaling up to a plant that is in the $1 to $1.5 billion range, and it is unclear who is going to provide all the guarantees required to get such a large plant to financing.

MR. ALEXANDER: Steve Greenwald, do you have the answer?

MR. GREENWALD: The first thing you learn about project finance is it is an exercise in risk allocation. You allocate risks to the parties who are best suited to take them. If a Kiewit, Fluor or Bechtel cannot get comfortable enough when building these facilities and partnering with a General Electric or Conoco to ensure they work, how are you going to ask a bunch of banks who are looking to earn a 1.5¢ or 2¢ spread on their money to take the risk that the plant will work? At the end of the day, either the construction contractors and equipment vendors will have to step up to the technology risk or the Department of Energy will have to do it. I think the Department of Energy will end up taking the risk on the first couple plants because I don't know that the Kiewits and Fluors will be comfortable doing it. That is really where the challenge lies.

MR. BRONICKI: The OPTI project will be the first gasifier built in Canada. It is actually under construction now. It is a 4,000-ton-a-day gasification unit. The key to gasification is to use the gasifier where you really need it. It will be used for the low grade, low value fuels that otherwise are just being left in the ground. The cost of gasification is reasonable as long as you use it for the right application.

MR. GREENWALD: I think gasification has a shot because banks are more comfortable with coal gasification. The construction contractors seem to be comfortable with it as well. However, going the next step through Fischer-Tropsch to liquids is more problematic. I think IGCC is next to impossible without someone stepping up because there is a history with IGCC and none of it is very good. However, gasification by itself is the one new area where I personally have a little bit of hope.

MR. SHELBY: The gasification on the OPTI-Exxon job was not wrapped. The project was not financed by having a Kiewit say, "We'll guarantee you that we will design it, build it and have it on line by a fixed certain date." Who is bearing that risk?

MR. BRONICKI: The owner. Somebody has to be brave, right?

MR. ALEXANDER: Merrick Kerr, Rentech is planning to build a commercial-scale coal-to-liquids plant and your company has an interesting strategy for getting past the problem that banks are unwilling to finance new technologies. Can you say what that strategy is?

MR. KERR: I wish I had been with the company in time to take credit for what is a very clever strategy, but I am new to Rentech. What we have done is acquire an ammonia fertilizer plant that operates currently with natural gas. We will then add a production line to make gas from coal. This syngas will supply the needs for the fertilizer plant and it will also produce extra gas that can be converted into FT liquids using a Fischer-Tropsch process. We will finance the part that makes the FT liquids using all equity. The first stage – the gasification line to make gas for fertilizer production – will produce 1,800 barrels a day and will be the first commercial-scale facility in the United States. This strategy gets us past the hurdle of having to ask banks to step up to risk associated with the FT technology.

We know the technology works. Our technology is similar enough to the technology that SASOL uses to take comfort from their long history of putting it to actual use. If we want to get this done, we cannot wait for the federal government to step up to project risk.

MR. ALEXANDER: Bob Kelly, DKRW is working on its own coal-to-liquids plant. What is its strategy for dealing with technology risk?

DR. KELLY: We are kind of hitting it straight down the middle of the fairway. We have acquired significant coal reserves to back up our activity. We have partnered with Arch Coal. We have acquired a couple hundred million tons of coal that will belong to the project company and will be a significant source of security. We have General Electric as our partner on gasification. We have Rentech as our partner on the Fischer-Tropsch process. We have a major Rocky Mountain refiner willing to take all the output under a long-term contract. We will do some hedging to fix the price structure on the oil. And you know what? My view is the market works. We have found a number of major engineering firms that are willing to work with us to understand the technology and put the wraps around it that are required to make the project financeable.

MR. ALEXANDER: Can you give us an idea of the size of the project? How much exposure and what type of liabilities are involved?

DR. KELLY: It is a little bit of apples and oranges because we have acquired the coal. The CTL portion is expected to produce about 11,000 barrels a day and will cost about $1 billion. The coal and related parts of the project cost around $400 million.

Our strategy is plain vanilla project financing. The Energy Policy Act authorized the Department of Energy to guarantee the debt on projects of this kind. The details of the DOE program are expected to be released later this year. We are one of the leading companies that DOE is expecting to apply.

If you look at the opportunities for putting stranded coal to use, I think the engineering companies will step up to the challenge. Even DOE is projecting that somewhere between one and two million barrels a day of oil equivalent can be produced over the next 10 to 20 years.

Government Role

MR. ALEXANDER: Steve Greenwald, how important a role will the US government have to play to get projects of this kind off the ground?

MR. GREENWALD: There is a huge role for the federal government to play if it really gets serious. Having a few companies like Rentech and DKRW build coal-to-liquids plants is not going to solve this country's energy problem.

It will not be solved, in my humble opinion, until the major oil companies have come on board. They will not do so as long as they are projecting long-term oil prices of below $30 a barrel and they see other opportunities to produce oil at lower cost. If the federal government is serious, it will have to say, "You build these things, and we will guarantee you we will buy the product from you at a 10% discount to the market, but in no event will the price we pay drop below" – pick a number – "$35 a barrel."

As a taxpayer — and I believe passionately about this — if the federal government ends up paying Exxon Mobil, for example, billions of dollars a year because the price of oil falls to $28 a barrel, I am fine with that. I think it is a win-win situation for the country. I don't understand why the federal government is not getting more serious about this.

We are working with the Department / continued page 30

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service commission had time for a full hearing. The production subsidiary set up a reserve on its books for the potential refunds, but never actually set aside any of the additional revenue in a formal reserve or bank account. The four distribution companies passed through the higher charges to their customers.

The public service commission ultimately allowed only a fraction of the rate increase.

The utility group tried to amend the tax returns for the period the rate increase was provisional to reduce the taxable income it reported in those years.

The IRS said it could not in a private letter ruling that the agency made public in mid-August. The ruling is Private Letter Ruling 200632015.

The IRS said the proper treatment is a deduction in future years when refunds are paid.

It rejected arguments by the utility group that its case is similar to other cases involving Houston Industries and Florida Progress Corporation — now called CenterPoint and Progress Energy. In those cases, the utilities passed through estimated fuel costs to customers, but were required by law to refund any over-recoveries.

The IRS said the case in the ruling is different. Houston Industries and Florida Progress had a fixed obligation by year end, when each could calculate its actual fuel costs, to refund any overcharges. In this case, it was not clear whether any refunds would be required. The utility group in the ruling continued to press for the full rate increase through both the full hearing and a rehearing.

Taxpayers usually withdraw private ruling requests rather than have the IRS rule against them. The utility group in this case may have wanted to put its regulators and possibly other utilities on notice. A private ruling is binding only on the taxpayer who requested it.

RESTRUCTURING A CONTRACT led to taxable income for a utility.

A 1978 federal statute called the "Public Utility Regulatory Policies / continued page 31

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of Defense on structures like this. That is one way to solve the price or cost-of-production problem. It does not get over the technology risk issues, but frankly, Exxon, Conoco or British Petroleum could build these things without requiring the Kiewits and Fluors of this world to wrap them. The reason they are not building them is they do not want to go into a venture that requires oil prices to remain at $35 a barrel to break even.

MR. ALEXANDER: Tom Shelby, what do you think the government should be doing?

Banks are assuming that oil prices will fall to the low $20 range per barrel in the downside cases they are running for current loans.

MR. SHELBY: It ought to help the contractor lower the risk profile as it is doing with nuclear power plants. I think the price of oil will settle at a level that makes it economic to pursue oil substitutes, but we have a technology problem. I agree with Steve Greenwald. Eventually Exxon or Shell will get comfortable enough with the technology to take the risk, but they are not comfortable with it today.

MR. GREENWALD: The early DOE loan guarantees will help. Giving a couple loan guarantees to a Rentech or to a DKRW will get people comfortable with technology, but it will not be sufficient to get majors to start building this stuff because they do not believe oil will remain at the $35 or $40 a barrel level required to break even on these projects over the long term.

MR. ALEXANDER: Merrick Kerr, one solution to the oil price conundrum would be to get a long-term offtake contract at a fixed price for the output. Do you see any chance of landing some type of collar or long-term contract for your syndiesel or your jet fuel or maybe even your fertilizer?

MR. KERR: Certainly, it would be the ideal to have. Another way to look at it is there is a 50-cent-gallon tax credit currently that is due to run out, but that were extended, say to 2020, that is equivalent to $21 a barrel in benefit.

If the price of oil falls back to the low $20 range, I am at $41 against a break-even point of $40. I won't make huge returns for the equity at that point, but I am certainly covering all my debt quite comfortably and I am making small returns. It would be nice to have an offtake contract, but with the loan guarantees and if the 50-cent-a-gallon tax credit is extended, then we should be financeable once we have that first plant done and with equity to get over the technology risk.

If somebody wants to give us an index price for the output with a floor and a ceiling, it would probably make a lot of sense. The Department of Defense is the obvious party to do that. The US military consumes hundreds of thousands of barrels a day to operate jets, tanks, ships and other equipment.

MR. ALEXANDER: Yoram Bronicki, what role do you think the federal government should play in promoting these technologies?

MR. BRONICKI: This is an area where I think taxation could do a lot. US consumption of fuel for transportation is about 14% of the world's oil supply. The average American in the west probably consumes about between two and three times more fuel than a European in a developed European country just because of the choice of vehicle. If the growth in US demand is 200,000 barrels a day of additional growth every year, then it is reasonable to cover it with the private efforts that we have been discussing today. But if the goal is to make a more significant dent in US oil consumption, then a lot more can be done by the government to encourage Americans to be more efficient in their consumption of oil.

The Europeans have decided that they want to use biodiesel and, therefore, the rest of the diesel is taxed, but biodiesel isn't. The government could do more to promote a change in public consumption patterns while raising money that could be used to subsidize other alternative energy projects.

The opportunities to have an effect are limited in terms of time. When everyone in China drives a big SUV, whatever the US does will no longer matter, but it is important in the meantime for world stability that the US be more engaged.

And just to give an example from the geothermal side of our business that shows where government help can lead, we build geothermal power plants today for maybe a quarter of what they cost when people started building them in the late 1970s or early 1980s. Government subsidies through higher tariffs helped take the industry through the learning curve. If the Kiewits get enough practice, they will build those plants more efficiently the next time. This is how a brave policy could actually change a lot over the next 10 or 15 years.

MR. ALEXANDER: Bob Kelly, I believe you have a comment?

DR. KELLY: I have two comments. First, we are happy the majors are not getting into this right now because even though they have tremendous capital, they are bigger and slower. They will eventually buy what we do and do it on a larger scale. Second, on the price of oil, there are huge external diseconomies in the oil market today because the price of oil does not reflect security spending to ensure that Middle Eastern supplies get to the United States. If you tack all that stuff on, there is a valid reason for the US government to promote coal-to-liquids and other alternative energy projects because it leads to a more sensible resource allocation.

We are spending the equivalent of $30 or $40 a barrel to ensure that guys like the Iranian oil company can send oil over here. That is a real misallocation. ◎

US Power Market Outlook

Four veteran power market forecasters participated in a roundtable discussion at a Chadbourne conference in June about the outlook for US wholesale power markets, which regions of the US offer the best opportunities for project developers, and what effect carbon controls are likely to have on the market when they are eventually imposed by the US government.

The panelists are Steve Dean, president of DAI Management Consultants, Art Holland, director of power and fuels price forecasting for Pace Global Energy Services, Michael King, a senior vice president and economist with NERA Economic Consulting, and Hugh Wynne, the senior utility analyst with the respected Wall Street research house, Sanford C. Bernstein & Co. The moderator is Keith Martin.

Upswing Through 2012?

MR. MARTIN: I saw an interesting / continued page 32

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Act," or "PURPA," requires US utilities to buy electricity from two types of power plants owned by independent generators. One type is small power plants of up to 80 megawatts in size that use waste or rewnewable fuels. The other type is cogeneration facilities that generate two useful forms of energy from a single fuel. An example is a coal-fired power plant that makes both steam and electricity. Congress amended PURPA in August 2005 to drop the requirement for utilities to buy electricity from such plants in regions of the country where there is enough of a wholesale market to provide independent generators with other outlets for their electricity.

Many utilities signed long-term contracts to buy electricity from independent generators in the 1980s and early 1990s. PURPA contracts are still used by some windpower developers.

The IRS released an internal memorandum in August that addressed the tax consequences to a utility that agreed to let the independent generator deliver electricity from any source — not just the eligible power plant — in exchange for a reduction in the price of electricity under the contract. The revised contract gave the generator the right to pay the value of the discount in cash in advance to the utility (and then charge normal rates later). The utility took the position that the cash discount was capital gain. An IRS agent disagreed on audit. The utility faced two hurdles in reporting the amount as capital gain. First, it is capital gain only if it represents an increase in value of the underlying contract. Second, there must be a "sale or exchange" of property to trigger capital gain. The IRS reviewer said the cash discount had to be reported as ordinary income. The case is discussed in a "field service memorandum" that the agency made public in August. It is FAA 20062801F.

INDIAN TRIBES will have a harder time issuing tax-exempt bonds under proposed regulations the IRS issued in August.

Tribes are treated like / continued page 33

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statistic in a book that Bernstein put out last week called "U.S. Utilities: The Outlook for Power Market Prices and Profits 2006 to 2010."

By 1999, reserve margins in the United States had reached 15%, which is considered the lowest prudent reserve margin. The building boom that was already in progress added 180,000 megawatts of new capacity over the five years from 2000 to 2004. That is against a total generating capacity in the United States — after this additional capacity was added — of 900,000 megawatts. US generating capacity increased by roughly a fourth in five years. That explains some of the trouble the independent power industry went through in the wake of the Enron bankruptcy. It also shows the boom-and-bust nature of our industry.

With that background, let me start with you, Art Holland. You told me during a panel discussion in January 2005 that the United States was about to move into the boom part of the cycle and that you thought the next boom might peak between 2010 and 2012. That was before oil prices surged. It was when gas prices were high. Is that still your view of what the current boom cycle will look like?

MR. HOLLAND: A couple of things have changed in the last 18 months. You mentioned oil and gas. If memory serves me, natural gas at the time we spoke was about $5 or $6 an mmBtu. Then we had Hurricane Katrina. Gas prices went up to $13 or $14 an mmBtu and have since declined from there.

The lingering aftershock of the storm is that there is more uncertainty today about gas prices. No one expected that gas prices would remain at $5 or $6 an mmBtu, but now there is even greater doubt. We recognize the need to bring in LNG, and we have made assumptions in our forecast about the number of terminals that will ultimately be built.

Capacity markets have also continued to develop in the United States. They should provide some incentives for people to build new power plants sooner than they would have otherwise.

The increase in gas prices means that we are likely to see fewer new gas-fired power plants than we would have otherwise, but because other technologies take longer to develop, that means the boom may not run its course as quickly as thought earlier. We expect over the next 20 years that as much as half of the new capacity will gas fired. Gas-fired capacity takes two or three years to build; other technologies take longer. Therefore, while we are moving into more of an upswing, I'm not so sure that it will peak in the 2010 to 2011 time frame. The cycle may take longer to play out.

MR. MARTIN: Steve Dean, Art Holland just said that he thinks as much as half the new capacity will be gas-fired. Do you agree with that assessment?

MR. DEAN: No. I think many more new plants will be base-load generation that will be coal or nuclear. This trend will be helped by the new incentives in the Energy Policy Act of 2005 for coal and nuclear. In the late 1990s, we built intermediate generation. There was no real base-load generation added to the grid. There is more interest this time around in base-load generation, whether it be coal or nuclear. However, what gets built during this phase may be driven by the changes in the regulation of air pollution.

MR. MARTIN: Mike King, one thing that seems to characterize the wholesale side of the electricity market in the United States is boom and bust, and 2004 seemed to be a pivotal year. It was the first year when demand for electricity increased more rapidly than capacity additions. Do you think we're on the upswing now and, if so, how long will that upswing last?

MR. KING: I think we will see a significant amount of new generation built. I would call this a return to the era of King Coal. I expect that almost all of the new generation will be coal fired. We may see a few nuclear plants, but I don't expect more than one or two. There are still doubts about the economic viability of nuclear plants in the long run without the government guarantees that will be offered to the first few plants. If coal is the dominant fuel in this cycle, then the cycle will take longer to run its course because it takes longer to build coal-fired power plants.

The real question is whether industry has learned when to stop building. This is not just an issue for independent generators. I was involved in the industry in the 1980s when utilities managed to over build as well. The question is whether we have learned our lesson from the last cycle.

MR. MARTIN: Art Holland, you believe as much as half of the new plants will be gas fired. Mike King, you are almost all coal. Steve Dean, you are also leaning more heavily toward coal. Art Holland, you look like the odd man out.

MR. HOLLAND: I am assuming that parts of the country that need capacity now will not be able to wait for new coal-fired power plants. There is also a lot of uncertainty about what new environmental controls will be placed on plants that use coal. These two factors make me think gas still has a significant role to play.

MR. MARTIN: Mike King, have you failed to take into account the cost of carbon controls in your forecast?

MR. KING: Carbon is definitely an issue. Carbon controls are likely to be imposed more rapidly in this country than I would have said a few years ago. I think there will be some new gas-fired power plants, but this is the era when we need base-load capacity. What are the technologies for base-load power? They are nuclear and coal. There are too many issues associated with building nuclear plants. That leaves coal, notwithstanding the expected carbon controls.

MR. HOLLAND: Let me stress that what I said is as much as 50% gas, not at least 50% gas. I put it that way because everything is on the table today. We used to think that gas-fired capacity was the answer to all of our problems, but there are so many uncertainties with respect to carbon and with respect to other environmental problems, the price of gas and the commercialization of new technologies that you really have to look at every technology today as a resource planner.

Regional Imbalances?

MR. MARTIN: Hugh Wynne, let me bring you into the conversation. I think this view that we are on an upswing assumes something about expanding spark spreads and higher electricity prices. Do you have a view on how long the current upswing will last?

MR. WYNNE: The most interesting thing about the current cycle in the northeast quadrant of the United States is that we are not getting new plant construction in time to address what I think will be a fairly severe supply and demand imbalance by the end of the decade. When you look at plants that are currently under construction — which are the only new plants that will be available in that time frame — the rate of capacity growth in the northeastern US is not keeping up with growth in demand.

The necessary consequence of that is that demand will consistently be supplied by incrementally more expensive power plants than are in the generating fleet today.

In the Atlantic seaboard, the additional supply will come from increasingly-expensive gas or even from oil-fired power plants.

That means peak power prices are likely to rise significantly. In off-peak hours and in the midwest, you will probably see a slightly different phenomenon, which is a shift from coal being on the margin to combined-cycle gas being / *continued page 34*

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sovereign governments. The Internal Revenue Code treats them like states for purposes of issuing tax-exempt debt. State and local governments can borrow at reduced rates to finance schools, roads, hospitals and other public facilities; anyone lending to them for such a purpose does not have to pay federal income taxes on the interest the lender receives.

However, tribes can only issue bonds to raise financing for "essential governmental functions." The IRS is concerned that some tribes are stretching this term beyond what was intended. New proposed IRS regulations say that an undertaking will not be considered an "essential governmental function" unless the tribe can show that "numerous" state and local governments have engaged in the same activity and financed it with tax-exempt debt "for many years." The tribe must also show that the project is not a commercial or industry activity. Examples of projects that qualify for tax-exempt financing under this standard are construction of an office building to house tribal offices or the type of lodge customarily owned and operated by a state park or recreation agency.

> *Tribes have limited authority to issue so-called "private activity bonds," or bonds for projects in which there will be more than 10% private business use. An example of private business use is where a facility is leased to a private company. However, such projects must be owned and operated by the tribe. They must be on Indian lands. The face amount of the bond issue cannot exceed 20 times the annual wages paid to tribe members and their spouses for working at the facility.*

SALES TAXES will be triggered in Texas when the owner of a company contributes equipment in kind to the company and the company also assumes liability for any loan to which the equipment was subject. Sales taxes are triggered by a transfer of equipment for "consideration." The Texas comptroller made the comment in a letter ruling in July. The ruling is No. 200602644L.

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on the margin. That is a very significant shift in terms of cost. It is a shift from $35 a megawatt hour to, say, $60.

The critical fact for me is that plants are not being built. That means electricity prices will have to rise as we dispatch from more expensive plants. The effort to implement capacity markets in places served by the New England ISO and PJM is a reaction to this problem. They would like to try to create revenues today by holding forward capacity auctions to encourage developers to build plants now so that the plants will be ready in 2010 and 2011. The delay in getting those markets up and running suggests that we will see a spike in prices in 2010, 2011 and 2012.

Anyone buying or lending against a US power plant that uses fossil fuels must make a judgment about how and when carbon controls are likely to be imposed.

MR. MARTIN: Hugh Wynne, continuing with you, what determines whether a particular region of the United States is a good market for wholesale generators? Is it spark spread, reserve margin or something else?

MR. WYNNE: I think it is the shape of the supply curve and particularly whether there are kinks in the supply curve that reflect a shift from one generation of technology to another. It is also the fuel that sets the price of electricity in a region and the outlook for that fuel price.

To take the second point first, markets like New England and many states in the Atlantic seaboard rely predominantly on gas-fired generation, and gas-fired generation tends to set the electricity price. The same is true of Texas. Gas prices are expected to fall over the period 2007 to 2010. If that proves true, then this will be a moderating influence on electricity prices in gas dependent markets.

There are large parts of the country like the midwest where coal is the dominant price-setting fuel, and the outlook for coal prices is, broadly speaking, more stable. But there may be upward pressure because of the cost of increasingly-stringent emissions controls on coal-fired plants, possibly including CO_2 emissions controls.

The second thing to look for, in addition to where fuel prices are headed, is the potential for a shift in technology from a relatively cheap technology to a more expensive technology. That shows up as a kink in the supply curve. For example, a shift from coal that has a variable cost of maybe $35 per megawatt hour to gas, which may have a variable cost closer to, say, $60 per megawatt hour, can occur because demand increases more rapidly than new coal-fired power plants can come on line. That sort of shift leads to an increasing marginal cost of supply and higher electricity prices.

MR. MARTIN: The supply curve reflects the price at which generators would supply a certain quantity of electricity. As the price goes up, more and more supply will be offered by the market. But the technology may affect how much is ultimately supplied at any given price, right?

MR. WYNNE: Yes. What keeps electricity cheap in the midwest today is that the incremental megawatt hour produced tends to come in most states from a rather large, relatively efficient coal-fired power plant. However, by the end of the decade, our expectation is that those large 1,000-megawatt base-load coal plants with scrubbers will probably be running flat out at full capacity. At that point, the incremental megawatt hour will come from a smaller, 500-megawatt 40-year-old coal-fired plant without a scrubber that may have a generating cost that is $10 higher. Those plants will eventually be running flat out, after which the next incremental megawatt hour will have to come from a gas turbine generator, which — even assuming $8 gas — would an operating cost of about $65 a megawatt hour.

As the market is forced to dispatch incrementally more costly units, you climb the supply curve in gradual increments and are forced to pay progressively higher prices so those units can cover their costs of operation.

MR. MARTIN: Art Holland, reserve margins are slipping to 20% in the midwest and they have already fallen below 15% in the mid-Atlantic states. These would seem the most fertile ground for independent generators. Do you agree?

MR. HOLLAND: Let's not lose sight of an important development. All of the regions you mention are in a part of the country that is interconnected with the PJM grid. That higher degree of interconnection allows for a lowering of reserve margins while maintaining of the same level of reliability.

Those reserve margins sound lower than what we have observed. They may reflect only what gets reported to the North American Electric Reliability Council, or NERC. The NERC figures generally only include plants that are under firm contracts to utilities. The figures do not include mothballed plants. When guessing at future prices, it is important to take into account mothballed plants that can come back quickly when scarcity pricing starts to become an issue in a region.

When interconnectivity and mothballed plants are taken into account, we don't think prices will spike as quickly as Bernstein does. Also, we think additional capacity will come on line along the mid-Atlantic seaboard fairly quickly.

MR. MARTIN: Steve Dean, what parts of country offer the best opportunity for generators looking to build new plants?

MR. DEAN: The west coast and the northeastern United States where the population density is greatest, but in those areas, you also have other issues. For example, both California and most of the New England states have moved to adopt state limits on carbon emissions. So you have parts of the country that will need additional electricity. They are making it hard to construct new coal plants. They probably don't like nuclear. They are pushing for renewables, but that will not be enough. The real need is for base-load plants.

MR. MARTIN: Mike King, do you agree that the west coast and New England are the two parts of the country that offer the best opportunity for new power plant construction?

MR. KING: Yes. Let's not lose sight of the fact that in places like California, you see many proposals by developers to build coal-fired power plants, but in states like Wyoming and Nevada that are close enough to supply their output to California.

Opportunity for Windfall Profits?

MR. MARTIN: Hugh Wynne, you implied in your earlier comments that the best opportunity for profit is to be a generator who uses something other than the price-setting fuel. For example, in regions of the country where coal sets the price of electricity, you are better off being a nuclear generator or perhaps a wind generator. In what parts of the country is coal the dominant fuel?

MR. WYNNE: The entire region */ continued page 36*

IN OTHER NEWS

BIODIESEL is losing tax subsidies in Germany.

Standard gasoline and diesel fuel are taxed in Germany at 45¢ a liter. However, biodiesel — or fuel made from plant oils — has been exempted from such taxes in an effort to encourage more Germans to use it. The government started collecting a tax of 9¢ a liter on it on August 1, and the rate will increase annually by another 6¢ until 2012 when it will reach the standard 45¢ rate that applies to other fuels.

The government is expected to order fuel suppliers to start blending biodiesel with fossil fuels at the pump, but it has not yet announced the ratio.

MINOR MEMOS. The IRS committed in a new business plan released in mid-August to issue guidance about when production tax credits can be claimed on electricity generated from biomass. The agency had been expected to issue the guidance last April, but at last check, the guidance had "bogged down." Also on the business plan are additional guidance on investment tax credits for coal-to-liquids plants, power plants that use advanced technologies to burn coal and other gasification projects. The agency has also committed to address whether telephone companies must report amounts received from federal universal service programs as taxable income.... A lessor had to pay gross receipts taxes in Indiana on the rents it received for leasing equipment to businesses located in Indiana. The lessor had no office in the state, and the leases were arranged by the equipment manufacturers who steered customers who wanted to lease — rather than own — to the lessor for prearranged lease financing. The state tax department assessed back taxes on the lessor on audit. The case is described in the July 1 issue of the *Indiana Register*.

— contributed by Keith Martin in Washington.

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between the Mississippi River east to Ohio and western Pennsylvania is one where coal is the dominant fuel. As you move into eastern Pennsylvania and upstate New York, coal is still the price-setting fuel during off-peak hours, but during peak hours, the fuel is gas. As you move farther east into New England, it becomes predominantly gas. The other wholesale region where you tend to see a lot of coal-fired generation is the southeastern US, excluding Florida, but it would be unusual to see coal as the price-setting fuel for more than 50% of the hours of the year. Finally, in the upper midwest — Wisconsin, Minnesota, Nebraska, the Dakotas — coal sets the prices of electricity perhaps 75% of the time.

The gas-fired regions are the remaining parts of the country — the southwest, much of the west as well as Florida, the Atlantic seaboard and New England.

MR. MARTIN: Mike King, the opportunity to earn a windfall profit from using a fuel other than the one that sets electricity prices sounds good in the abstract, but it assumes fuel prices will remain in constant relation to one another, apart from wind where there is no charge for the fuel.

MR. KING: I think that's a key issue. The way that you make the most money is to have some other plant setting the price. If the price for electricity it set by a $60 gas plant, that is pretty important to a coal-fired power plant because the $25 spread between the $35 cost of the coal plant and the $60 price set by the gas plant creates a sizable profit margin. Coal prices tend to be stable over the long haul. The big uncertainty is what will happen to gas prices.

I have been in this business now for 25 years. There have been many times during that period when people have been alarmist about oil prices. Wasn't it Hubbard, the state geologist in Pennsylvania, who said in the 1880s that we had at most 10 years of oil left? These things are notoriously difficult to predict.

We are in an era when gas prices are persistently in a range of $8 to $10 an mmBtu or higher. That makes coal look awfully attractive. If gas prices were to drop to $3 or $4 or, God forbid, Standard & Poor's downside case of $2.75 an mmBtu, then coal is going to look a lot more troubled.

We made a mistake the last time around. The supply surge that began in 1997 or 1998 and culminated in adding 180,000 megawatts of new generation was almost all gas fired. We know that we probably needed some base-load power plants out of that. Now we are in a situation where many of our base-load plants are aging and will have to be replaced.

The 900-pound gorilla in the room that no one has acknowledged yet is what is the regulatory scheme in the United States. It is not just a question of gas prices in relation to coal prices, but also whether we will continue to rely on a competitive wholesale power market or whether utilities will own the next round of plants and put them into their rate bases.

MR. HOLLAND: Our expectation at Pace Global is gas prices will fall through the 2012, 2013 and 2014 time frame. We think gas prices will reach bottom sometime in 2015 and then ease back up. However, we do not want anyone to hang his hat on a particular gas forecast. We now build all of the forecasts that we publish quarterly as stochastic bands, and those stochastic bands for gas are extremely wide.

I agree with Mike King. While the relative prices of gas and coal and other fuels are important, the real opportunities for independent generators turn not only on the relative spreads between fuels, but also on scarcity pricing. That is the promise of forward capacity markets to take some of the boom and bust and provide some of that scarcity pricing to developers in advance of when the market is short electricity.

The high price of gas will take you to $100 a megawatt hour. Scarcity will take you to $1,000 or $2,000 a megawatt hour. The key is to watch how effectively forward capacity markets induce developers to build before low reserve margins start being reflected in higher prices.

Other Variables

MR. MARTIN: Steve Dean, we have been talking about how fuel prices might provide opportunities for independent generators. What are other key variables?

MR. DEAN: One factor is the type of carbon controls that emerge. Less than 10% of the capital cost of a coal-fired power plant built in the 1980s went to air emission controls. The mercury controls that the Environmental Protection Agency adopted earlier this year will add another 2% to cost by 2010. Carbon controls are likely to add another 4% to 5%.

MR. MARTIN: That is 5% additional cost to generate a megawatt hour?

MR. DEAN: Exactly. Someone running a combined-cycle gas-fired power plant faces no additional cost due to mercury controls and about half the cost from carbon controls as for a coal-fired power plant. Therefore, whether you use gas or coal, your costs will increase. If you own a coal plant in a gas region, your margin will be squeezed. That is not something that many people have taken into account adequately in their calculations.

MR. MARTIN: Are there other factors that generators should take into account in their calculations? For example, how quickly will new nuclear power plants add significantly to US generating capacity? Are renewables likely to soak up the entire load growth?

MR. DEAN: There are about 35 new nuclear plants being constructed today in other countries. The US Nuclear Regulatory Commission is hiring 4,000 engineers this year to gear up for expected new license applications. Many of the large nuclear utilities are gearing up to submit applications. We will see new nuclear plants. The US government is offering production tax credits and taking on cost-overrun risk as an incentive to build. Any cost overruns above 125% will be borne by the taxpayers.

Effects of Carbon Controls

MR. MARTIN: Hugh Wynne, you said during a very interesting call with institutional investors that carbon controls, which are expected to be imposed eventually by the United States, will add between $3 and $11 a megawatt hour to produce electricity from gas and between $8 and $28 a megawatt hour to produce electricity from coal. However, you tended toward the bottom end of that spectrum. Why?

MR. WYNNE: It was partly a matter of editorial style. It is hard to publish research reports that foresee a change in the price of power on the order of 100%. I don't think the world works that way. Such changes tend to be mitigated by demand response. There are also substitutions in supply. This makes me gravitate toward the lower end of price forecasts.

Yet, even at the lower end of the spectrum, the changes are likely to be very significant. My point is that even if we accept a very conservative view of the cost of CO_2 emissions, the impact will still be huge.

There is another important point. There are likely to be sources of CO_2 emissions reductions — and, therefore, sources of CO_2 credits — that are much less costly than those that are available to the power industry alone. In other words, it may be very expensive to build power plants that use coal but do not emit CO_2, like IGCC plants, but it may be even more expensive to retrofit plants that currently emit CO_2 in an effort to minimize their emissions. Further, it may be very expensive to substitute lower CO_2 fuels like gas for coal. Those costs may be much higher than the costs that would be incurred by other sectors of the economy to reduce their CO_2 emissions.

One of the beauties of the regulatory schemes that are being discussed in the Senate today is that they tend to encompass virtually all sectors of the economy.

The result is the incentives will be greatest for sectors of the economy that are the most wasteful users of energy to cut back first on their uses of hydrocarbon fuels. The cost of cutting energy use in those sectors will be less than if we tried to cut CO_2 emissions by focusing on the power sector alone. Residential and transportation uses of hydrocarbon fuels will be curtailed first. That's another reason why I think the cost increases in the power sector will fall at the lower end of the spectrum.

MR. MARTIN: Steve Dean, you are involved in valuing power plants in acquisitions. Are you taking into account the possibility of carbon controls and, if so, how?

MR. DEAN: Yes, we are. When we value power plants, we assume that a carbon tax will take effect in about 2010. We assign it a 50% probability. It adds 4% to 5% to the cost of a typical 1980s coal-fired power plant and about half that much to the cost of a combined-cycle gas turbine plant. We are also assuming that any coal-fired power plant will use activated carbon injection to control mercury emissions, which will add another 2% to operating costs.

MR. MARTIN: Mike King, you also do valuations. Are you taking the same approach as Steve Dean?

MR. KING: Yes. We believe carbon controls will be put in place later than 2010. We tend to look at these things in terms of the implications of an $8 price for an allowance, or the right to emit a ton of carbon emissions. How an $8 allowance price would affect the market is unclear. It is not as simple as saying the price to generate a megawatt hour of electricity from coal has just risen by $8. Most likely, there will be price pressure on natural gas because it will be a premium fuel. The point is you have to play out a string of consequences to figure out what effect carbon controls might have on the value for a particular plant.

MR. MARTIN: Hugh Wynne made the point during a call with institutional investors that the Senate Energy Committee is proposing carbon controls not be imposed on the generators who buy the fuel but on the suppliers of fuel. They are fewer in number. It is easier to require that allowances be purchased by them.

Another interesting point he made is / continued page 38

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that he doesn't see the federal government just handing out allowances, given its budget problems. He thinks that this will work like radio frequencies where allowances are auctioned off by the government to help close the budget gap. Mike King, do you think that is the most likely outcome?

MR. KING: I think that is highly unlikely.

MR. MARTIN: Why?

MR. KING: If we look at the trading schemes that have been put in place, we know of no circumstance where allowances have been auctioned. There are lots of political issues associated with carbon controls. We are in an environment where a 72% rate increase in Maryland led to a political revolt, fed largely by *The Washington Post*. Price increases cause political backlashes. We just don't believe you will see politicians touching the third rail by making a carbon scheme look like a tax. We think they will have to grease the wheels for any sort of carbon scheme to be enacted by handing out allowance. A tax scheme just makes losers. It makes no winners. An allocation scheme might get some people behind the proposal.

MR. MARTIN: Steve Dean, what calculations should a savvy banker do when lending to a greenfield plant today that uses fossil fuels?

MR. DEAN: There are two issues for the banker. He has to assign a probability to how likely carbon controls are to be imposed. He has to make judgments about when they are likely to be imposed and at what level. In my mind, there is no doubt that such controls will add to the operating costs of both gas- and coal-fired power plants. The issues are how much and when.

MR. MARTIN: And your guess is a 50% likelihood?

MR. DEAN: Yes, 50% in 2010.

MR. MARTIN: Hugh Wynne, I think you believe carbon controls are almost a certainty, am I right?

MR. WYNNE: My guess is 30% to 50% probability by 2010.

A key fact that goes unrecognized with CO_2 emission limits is that there is no way for the power sector to comply with them other than by curtailing output or by substituting higher cost fuels. Adding pollution controls to older plants is not really an option because it is not economic to retrofit with the available technologies.

Therefore, if you want the power sector to produce less CO_2 — and the same is probably true of other big industrial facilities and certainly true of houses and cars — the only way they can do it is by using fewer hydrocarbon fuels. That means producing less electricity in the case of power. It means that imposing a cap on CO_2 emissions is like imposing a cap on power output. Utilities will have a choice of reducing output or switching from coal to gas plants, but either way, the price of electricity will increase just as it has increased in Europe when CO_2 emissions limits were imposed there.

The real question is who will benefit from that price increase. Will the benefit be a windfall profit for certain utilities, which is the way it has worked in Europe?

The only way it will not be a windfall profit in the United States is if the government sells the allowances. The proceeds of the allowance sale will give the government resources to mitigate the effect of the price increases. They could be used for something crudely popular like a tax reduction or rebates on fuel bills to consumers. They could be used to stimulate technology investments that reduce CO_2 emissions. They could be used to mitigate the effect on certain sensitive sectors of the economy that might be disproportionately harmed from the emissions limits, like coal miners and owners of coal-fired power plants.

MR. MARTIN: Art Holland, I can't help but observe that the last time you and I spoke, you pointed out that one lesson forecasters took away from the last merchant plant boom was to be less certain about their forecasts. You spoke today about stochastic bands. This reminds me of what tax lawyers do. We have a range of opinions — this "should" be how the law works, or it is "more likely than not" how it works, or there is "substantial authority" for your position. Is this the grim future for price forecasting — that you will come off sounding like tax lawyers? [Laughter.]

MR. HOLLAND: It depends on how you plan to use the forecast. A developer using such a forecast needs a most likely case, and we will provide that, and he also needs to take into account a worst case.

Meanwhile, a utility using forecasts for resource planning should use the full range of possible outcomes. We want it to look at the entire range of power prices, gas prices, coal prices, emission allowance prices and a number of different portfolio mixes and to assess how each of those portfolios performs across the entire range of possibilities. Most utilities go with the portfolio that provides the best protection on the downside even though it doesn't necessarily produce the best return on the upside. ◎

New Rules for Pipeline Gas Quality

by David Schumacher, in Houston

A new policy statement issued by the Federal Energy Regulatory Commission in July will let each interstate gas pipeline and its customers work out quality standards for gas the pipeline will transport. The standards must be within certain general parameters.

The policy statement will affect all participants in the gas industry, including suppliers of liquefied natural gas, or LNG, and end users of gas like owners of power plants.

The commission adopted a case-by-case approach rather than impose uniform gas quality standards that would apply to all pipelines.

Background

The agency was prompted to act by an increase in the last five years in the volume of administrative litigation before FERC over pipeline gas quality specifications. A lot of the litigation is linked to actual or proposed LNG imports and to unprocessed, non-conforming gas being delivered to pipelines for transportation. In the past, pipelines were more likely to be asked to transport processed gas.

Each interstate pipeline in the United States imposes gas quality specifications as part of a tariff it has approved by the Federal Energy Regulatory Commission. However, the specifications are not uniform across the industry. Because of this lack of uniformity, FERC has tried to achieve an industry consensus on the proper regulatory approach to gas quality specifications. The Natural Gas Council, an organization of representatives from the various sectors of the natural gas industry, produced two reports on the issues of gas quality and interchangeability.

Despite these efforts, no industry consensus developed on a uniform approach to gas quality specifications. It also became clear that additional research is needed to address some of the issues facing the industry. As a consequence, FERC decided to handle quality issues on a case-by-case basis — at least for now.

The policy statement addresses two issues under the heading "gas quality specifications." They are "gas quality" and "interchangeability."

"Gas quality" primarily addresses the issue of hydrocarbon liquid dropout. When natural gas is produced, its principal component is methane. The gas stream also contains other hydrocarbons and contaminants. When natural gas is processed after production, most of these other hydrocarbons and contaminants are removed from the gas stream. Sometimes it is better economically for the gas producer to transport and sell unprocessed gas instead of paying for a processing plant to strip the other hydrocarbons from the gas stream before transporting and selling the gas. Hydrocarbon dropout occurs when unprocessed gas is delivered into the pipeline and, due to changes in temperature and pressure, the heavy hydrocarbons in the unprocessed gas assume a liquid form and "drop out" of the gas stream. These heavy hydrocarbons can adversely affect the operation of pipelines, gas distribution facilities, and an end user's equipment, such as a gas-fired turbine.

The pipelines have used different methods to regulate hydrocarbon liquid dropout in their systems. Each approach has its drawbacks.

Gas "interchangeability" refers to the extent to which a substitute gas can safely and efficiently replace gas normally used by an end user. Interchangeability is important to interstate pipelines because the gas a pipeline transports typically comes from multiple sources. The most widely used measure of interchangeability is the "Wobbe index." Through industry efforts to achieve a consensus on appropriate gas interchangeability standards, it became apparent to FERC that additional research is needed on the best measure of interchangeability. Most of the available science on gas interchangeability dates from the 1930s and 1940s. Until additional research is completed, FERC concluded that it would not be appropriate to adopt a uniform gas interchangeability standard.

New Rules

The new FERC policy on gas quality and interchangeability adopts five basic principles.

First, pipelines can enforce only the quality specifications in the tariffs FERC has approved. This will significantly restrict the ability of pipelines to use operational flow orders, or OFOs, to impose gas quality specifications on shippers, a practice that was becoming more common among pipelines.

Second, pipeline tariff provisions on gas quality and interchangeability can be flexible to enable / continued page 40

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each pipeline to adapt to rapidly-changing circumstances. Flexible tariff provisions will allow the pipelines to balance safety and reliability, on one hand, and maximize the quantity of gas transported on the other.

Third, pipelines should develop appropriate gas quality specifications in consultation with their customers. The agreed-to gas quality specifications must be based on sound technical, engineering and scientific considerations.

Fourth, the Natural Gas Council reports on gas quality and interchangeability should provide a common reference point to the pipelines and their customers for resolving gas quality and specification issues.

Finally, FERC will resolve disputes between a pipeline and its customers over gas quality and interchangeability issues on a case-by-case basis. FERC will give significant weight to the Natural Gas Council reports if asked to resolve these disputes. FERC recognizes that issues such as the configuration and geographic location of a pipeline, the ability of a pipeline's customers to have access to processing facilities, gas pressure and temperature on a pipeline, ambient conditions surrounding a pipeline, historic characteristics of the gas transported through a pipeline, the requirements of the end users' equipment in a market, and the needs of interconnecting pipelines will affect the ultimate gas quality and interchangeability standards that are adopted by a particular pipeline.

The new FERC policy will apply to developers of LNG receiving terminals. FERC will require each terminal developer seeking authority to construct and operate an LNG receiving terminal to include in its permit application information that demonstrates the compatibility of the LNG that will be delivered to its project with the gas quality and interchangeability requirements of all interconnecting pipelines. FERC refused to impose on LNG receiving terminal developers specific obligations for merchantability of imported LNG. Additionally, LNG receiving terminal developers will not have to identify, or compensate parties for, adverse impacts arising from differences between the quality of imported LNG and the quality of domestic natural gas. ◎

FERC Makes It Easier to Charge Market Rates for Gas Storage

by David Schumacher, in Houston

Owners of underground natural gas storage facilities should find it easier to charge unregulated, market-based rates for their services under new rules announced by the Federal Energy Regulatory Commission in June.

FERC hopes the new rules will lead to construction of more gas storage facilities. Additional storage sites are needed to meet increasing demand for natural gas and to help mitigate price volatility in the natural gas market.

Owners of storage facilities have had historically to charge cost-of-service rates for storing gas. In recent years, FERC has allowed them to charge market-based rates, meaning whatever they can negotiate with customers. However, to qualify for market rates, a storage provider must demonstrate that it lacks market power in the geographic and product markets in which it will provide services.

Even then, approval to charge market rates is not automatic. FERC has rejected a number of proposals on grounds that customers in the area have few alternatives but to use the storage facilities at issue. The agency has taken a narrow view of what qualifies as a practical alternative. The new rules represent a rethinking of this approach. The agency is concerned that its current market power test is inhibiting construction of new storage capacity because it is too restrictive.

Congress gave the agency a push. The new Energy Policy Act that was enacted in August last year amended the federal Natural Gas Act to allow anyone building a new gas storage facility to charge market-based rates without having to satisfy the FERC market-power test. The developer must merely demonstrate that market-based rates are in the public interest and are necessary to encourage construction of his or her project and consumers will be protected against the exercise of "market power" by a developer.

The new rules address two primary issues. First, they ease the evidentiary burden under the FERC market power test. This should make it easier for owners of existing facilities to receive authority to charge market rates. Second, they list criteria that owners of new storage facilities must satisfy to receive authority to charge market rates under the new energy law without having to pass the FERC market power test. The new rules apply to all types of services that underground storage providers make available, not just firm storage services.

According to the Energy Information Administration, there are more than 390 underground storage facilities in the United States. Estimates of working gas capacity at these facilities range up to 4.7 trillion cubic feet (tcf). More than half this capacity is subject to FERC ratemaking jurisdiction under the Natural Gas Act. FERC has jurisdiction over facilities that store gas moving across state lines.. The US consumes approximately 22 tcf of natural gas per year.

Since 1989, available storage capacity has increased by only 1.4%. The demand for underground storage capacity is likely to increase due to the increases in LNG imports and continued growth in natural gas consumption. The National Petroleum Council estimates that an additional 0.7 tcf of working gas capacity will be needed by 2025.

Underground storage is important to the efficient operation of the US gas market. With storage, buyers can purchase gas during periods of low demand, when the market price is generally at lower levels. This gas can be injected into storage and used during periods of peak demand. Thus, storage can have the effect of dampening price volatility and allowing more efficient use of the infrastructure necessary to produce natural gas and deliver it to market.

Market Power Test

Under the market power test as currently administered, a storage owner seeking authority to charge market-based rates must show that there are good alternatives to its services in the relevant product and geographic markets and that these markets are not concentrated. FERC defines a "good alternative" as a service that is available soon enough, has a price that is low enough, and has a quality that is high enough to permit customers to substitute the alternative service for the services of the underground storage provider.

The new rules modify the market power test by expanding the types of service that FERC will treat as a "good alternative" to the services of the underground storage provider. Storage owners will now be able to demonstrate that non-storage services, such as pipeline transportation services (including released capacity), local gas production, services that a local distribution company provides, and even financial instruments like futures contracts are acceptable substitutes to the provider's storage services.

The burden will still be on the applicant for market-based rates to demonstrate that non-storage services are a good alternative to its storage services. To meet this burden of proof, the applicant will have to demonstrate that the proposed non-storage alternative will be available during periods of peak demand, and will be available at a price and will have a quality to meet customer needs as well as the storage services of the applicant.

This revised market power test will apply literally not only to new underground storage capacity, but also to underground storage facilities that are currently in operation. (However, owners of new projects have two bites at the apple. If they flunk the market power test they can still seek authority to charge market rates under the new relaxed standards in the Energy Policy Act.)

Underground storage providers with market-based rate authority will not have to file a revised market power analysis every five years, as was originally feared. Instead, every underground storage provider offering services at market-based rates will have to notify FERC if there have been changes in circumstances that affect the provider's ability to exercise market power. In addition, if an underground storage provider charging market-based rates has a market share greater than 10%, then FERC will consider on a case-by-case basis whether the provider should be subject to additional reporting requirements.

FERC will require companies providing storage services at market-based rates to account separately for all costs and revenues associated with the facilities used to provide market-based services. FERC wants to make sure that a company, such as a regulated pipeline, providing services at both cost-of-service rates and market-based rates is not using its cost-based services to subsidize its market-based services. Such cross-subsidization would provide a pipeline's market-based services with an unfair rate advantage over the services of an independent storage developer.

FERC will not change other aspects of its market power test. Consistent with its current practice, FERC will not permit an applicant for market-based rates to include in its evidentiary case services of its affiliates, including services that are offered by an affiliated interstate pipeline, as examples of good service alternatives. Additionally, FERC will not change how it defines the relevant geographic market for its market power analysis. Finally, FERC will continue to consider a market concentration measurement of / continued page 42

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1800 using the Herfindahl-Hirschman index as an indicator that the relevant markets are too concentrated to allow an underground storage provider to charge market-based rates.

Energy Policy Act

The Energy Policy Act allows FERC to authorize storage projects placed in service after August 8, 2005 to provide service at market-based rates even if the underground storage provider cannot demonstrate that it lacks market power.

Specifically, an underground storage provider could be given authority to charge market-base rates if such rates would be in the public interest, they are necessary to encourage the construction of storage capacity in the local area, and customers would be adequately protected. FERC must ensure that reasonable terms and conditions for storage services are in place to protect consumers, and it must review periodically whether the market-based rates of the provider are just, reasonable and not unduly discriminatory or preferential.

Intrastate storage providers seeking to provide interstate services also would be able to charge market-based rates under these new Energy Policy Act provisions.

The Energy Policy Act test applies only to underground storage providers that cannot otherwise demonstrate to FERC that they lack market power. Thus, an underground storage provider can obtain market-based rate authority either by demonstrating that it cannot exercise market power in the relevant markets or it can meet the requirements of the Energy Policy Act. If an underground storage provider opts for the Energy Policy Act test to obtain market-based rate authority, it is presumed to have market power.

In determining whether market-based rates are consistent with the public interest, FERC will consider, among other factors, the riskiness of the project and the investment necessary to fund its construction. A showing that the use of market-based rates is necessary to attract financing would indicate that market-based rates are consistent with the public interest. FERC believes that independent storage providers are more likely than existing pipeline companies to need market-based rates to attract investment in a new project. Thus, existing pipeline companies may have a hard time getting market rate authority if they have market power.

An underground storage provider's use of an open season, through which capacity is offered to the market at cost-based rates, is one means through which the provider can demonstrate that market-based rates are necessary to encourage construction of storage capacity. If sufficient interest in the storage capacity at cost-based rates is not demonstrated through the open-season process, FERC will consider this as evidence that the provider must have market-based rate authority to attract market interest.

An underground storage provider can demonstrate that storage services are needed in a particular area if it can present evidence that there is a lack of storage capacity or existing capacity is fully subscribed. Additionally, the provider can show that its project is needed to alleviate pipeline constraints and high or volatile natural gas prices in the local area.

Whether customers are adequately protected, and whether reasonable terms and conditions for storage service are in place, could be demonstrated in different ways. For example, if an underground storage provider has conducted an open season for available capacity, this could demonstrate that interested customers are given non-discriminatory access to available storage capacity. Also, the underground storage provider must demonstrate that the Energy Policy Act authorization will not result in existing customers being subjected to additional costs, risks or degradation to their services. Finally, if the underground storage provider has on file with FERC a tariff or statement of operating conditions spelling out terms and conditions of the provider's storage services, this will be an indication that there are in effect terms and conditions of service that will protect the provider's customers.

FERC will not impose cost-based caps on the rates that could be charged by an underground storage provider obtaining the Energy Policy Act approval to charge market-based rates.

FERC will not impose specific requirements on these underground storage providers to ensure that they are not withholding capacity to drive up rates. However, the applicant must demonstrate that there are adequate protections in place to ensure that the underground storage provider cannot exercise market power by withholding capacity from the market. Such protections could include a reserve price for capacity and a commitment to provide available capacity to interested customers willing to pay the reserve price.

FERC will not require successful applicants to deliver to FERC any more information for purposes of future monitoring than regulated entities are currently required to provide. ◎

Court Rejects Attempt to Cancel Contract in Bankruptcy

by Ted Zink and Seven R. Rivera, in New York

A US appeals court appears in a strongly-worded opinion in July to have definitively closed the door on efforts by Mirant, a US independent power company, to use its bankruptcy as justification to walk away from commitments it made to the Potomac Electric Power Company, a utility, when Mirant bought the utility's power plants.

The case is important because it sheds light on how great a risk a seller faces that a buyer who later goes bankrupt might be able to walk away from part of the business deal.

At issue in the case was the fate of a "back-to-back agreement" under which Mirant promised to assume obligations that Pepco made to other independent generators to buy their electricity under long-term contracts.

The fight between Mirant and the utility has a long and tortured history that the judge in the case summarized as "Mirant's unrelenting and unjustified effort to avoid a legitimate contractual obligation it now views as a bad deal."

The decision is moot. The parties settled the case before the decision was rendered. The motion to approve the settlement was still pending before the bankruptcy court when the *NewsWire* went to press. The appeals court issued its order after already receiving lengthy submissions from the parties and hearing oral arguments on the issues before the settlement. The court appeared to acknowledge the settlement by requiring that its order should not be published and limiting any precedental value strictly to the facts of this individual case.

Background

Mirant signed a contract in December 2000 to buy a group of power plants from Pepco. As part of the deal, Mirant also agreed to assume Pepco's obligations under several power purchase agreements that committed Pepco to buy electricity from third parties. At the time of the negotiations, both Mirant and Pepco acknowledged that the purchase price for the power under these power purchase agreements was above market and the contracts in question had an agreed "negative value" of approximately $500 / continued page 44

million. Consequently, the purchase price for the power plants was reduced from $3.2 billion to $2.65 billion.

Pepco notified Mirant at the closing that some of the power purchase agreements were unassignable; therefore, the parties entered into a back-to-back agreement that committed Mirant to purchase from Pepco, at Pepco's cost, all capacity, energy, ancillary services and other benefits that Pepco was obligated to purchase from the third parties under the unassignable power contracts. The back-to-back agreement is expected to cost Mirant approximately $10 to $15 million a month until the purchase obligation expires.

Mirant filed for bankruptcy protection on July 14, 2003. Within two months of filing for bankruptcy, Mirant filed a motion with the bankruptcy court to reject the back-to-back agreement. Mirant wanted to limit the rejection to only the back-to-back agreement while keeping the Pepco power plants and while preserving a right it had to connect the plants to the Pepco grid.

Mirant's motion to reject the back-to-back Agreement started a chain of intense litigation that spanned three years and several courts. The rejection motion was first moved from the bankruptcy court to a federal district court, which denied the motion on grounds that a bankruptcy court cannot affect a matter that the Federal Power Act assigns to the Federal Energy Regulatory Commission. Mirant appealed the district court order to the US appeals court for the fifth circuit, which reversed the order and held that a bankruptcy court (or district court) does in fact have the authority to allow a power contract that is subject to FERC regulation to be rejected. The appeals court said the Bankruptcy Code trumps FERC when it comes to assumption and rejection of energy contracts and remanded the proceeding to the district court for a decision on the rejection. However, the appeals court suggested that the district court should use a more rigorous standard before rejecting the back-to-back agreement than the usual "business judgment standard" that usually applies in bankruptcy proceedings when debtors wants to reject contracts. The more rigorous standard would take into account the public interest in the transmission and sale of electricity.

When the case came back to it, the district court held that the back-to-back agreement could not be separated from the broader purchase of the Pepco power plants and, thus, was not eligible for rejection under the Bankruptcy Code. The Bankruptcy Code requires that an executory contract must be assumed or rejected *in its entirety* to / continued page 44

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prevent a debtor from keeping the benefits of a contract while rejecting the burdens to the detriment of the other party to the agreement. Mirant again appealed to the US appeals court for the fifth circuit.

While awaiting the results of the appeal, Mirant filed a second rejection motion. This time it said it wanted to reject the power plant purchase and the back-to-back agreement together. However, Mirant excluded from the rejection "ancillary agreements," including a right to connect to the Pepco grid and certain lease assignments and easements. The issue of whether or not these "ancillary agreements" meant Mirant was not rejecting the contract in the entirety was argued before the district court, but the case was suspended while Mirant continued to pursue other aspects of the case before the appeals court. However, the district court ordered Mirant to continue to perform under the back-to-back agreement in the meantime. Mirant then appealed this order to the appeals court as well.

In June 2006, while the several appeals were pending, Pepco and Mirant reached a settlement. Notwithstanding the settlement, the appeals court issued its order on both appeals on July 19, 2006.

Appeals Court Order

The appeals court worked through a thicket of issues. One was whether the back-to-back agreement could be rejected without also rescinding the power plant purchase. The court said whether two agreements are "severable" is a matter of state law. The documents in this case said District of Columbia law would control. Analyzing DC law, the court determined that the parties assented to "all of the promises," including the back-to-back agreement, the sale of the power plants, the interconnection agreements and the lease agreements, as a "single whole." There were no separate contracts or transactions and everything was included in the overall deal and executed on the same day as one package. Further, there was a single consideration for the total agreement as evidenced by the purchase price (which was reduced by the cost of the back-to-back agreement). The court asked rhetorically why Mirant would enter into a legal obligation to purchase power at an above-market rate unless it was in exchange for something Mirant considered valuable, which in this case was the power plants and associated agreements.

Next, the appeals court determined that the district court applied the proper standard for rejection in this case because the purpose of allowing a debtor to reject a contract is to free the debtor from agreements that would hinder or disable its reorganization. The court noted that Mirant has already successfully emerged from bankruptcy and the unsecured creditors in the case received payment in full on their claims. Therefore, it cannot be argued that the back-to-back agreement is causing any hindrance to a successful reorganization because the reorganization is already successful and complete.

Finally, the court held that the district court correctly required Mirant to continue to perform under the back-to-back agreement pending the appeal. The court reiterated that a debtor is not entitled to reap the benefits of a contract without suffering the burdens as well and found that Mirant continued to benefit from ownership of the power plants. Therefore, the district court was right to force Mirant to continue to pay for them.

Conclusion

The judge in the case concluded his decision with a strongly worded admonition against any further appeals by Mirant. Specifically, the court said "any future appeals that continue the pattern of attempts to reject the [back-to-back agreement] or efforts to refuse payment pending rejection may well invite the most severe sanctions available to this court."

Even though the decision does not have official precedential value beyond the scope of the Mirant case, it provides useful insight by its forcefulness into how a court is likely to view an integrated asset purchase and sale agreement that includes provisions for out-of-market power purchases as part of the consideration. When negotiating or entering into these arrangements, it is important to create and emphasize as much as possible the indicia of separate agreements and consideration for each part of the transaction if the buyer wants to preserve the right to discharge these obligations in bankruptcy. This can perhaps be done by express language in the documents evidencing this intention or by entering into complete and separate agreements with respect to each segment of the transaction. ◎

Environmental Update

IFC Guidelines

The International Finance Corporation proposed revisions in early August to some of the environmental guidelines with which it requires borrowers to comply if they want to borrow money from the IFC to finance projects in developing countries. Many private banks use same standards. The IFC is part of the World Bank.

The existing IFC guidelines were drawn initially from a "Pollution and Prevention Abatement Handbook" issued by the World Bank in 1998 and then supplemented through a series of other guidelines published on the IFC website between 1991 and 2003. Seventy three guidelines currently exist, and the IFC committed earlier to updating them.

The IFC issued its first batch of draft guidelines for public comment on August 2. They consist of a set of "General EHS [Environmental, Health and Safety] Guidelines" and 20 industry sector-specific guidelines. The latter include guidelines for wind energy projects.

The draft general EHS guidelines contain a considerable amount of detail. They address processes, procedures and performance targets for air emissions, ambient air, wastewater, hazardous materials, solid and hazardous waste, noise, contaminated land and construction and decommissioning projects, as well as standards for human, occupational and community health and safety.

The scope is very ambitious, and the document reflects a change in philosophy from the existing guidelines. Other than standards for ambient air pollutants and noise and efficiency criteria for air emissions control technology, the draft guidelines do not rely extensively on numeric values. Instead, they emphasize processes that must be undertaken and sensitivities that should be considered, not only at the planning and construction stage, but also throughout the operational life of the project.

The draft general standards are meant to be supplemented by the industry-specific criteria. For example, the draft wind energy project environmental guidelines address both on-shore and off-shore wind projects and focus on impacts to local inhabitants and birds and other species. Most of the solutions are oriented toward selecting site locations as far away as possible from nearby residents and significant bird and animal populations. Because wind projects emit few pollutants, there are almost no numeric performance standards, except that noise increases should be limited to three decibels at the nearest receptor.

Once adopted, the environmental guidelines will take on significance beyond their use in IFC and World Bank transactions.

The guidelines are commonly used by a variety of multilateral lending institutions. They have also been adopted by the 40 mostly private international lending institutions who are signatories to the "Equator principles." These institutions have reaffirmed their commitment to the newly-revised IFC guidelines.

Additional draft sector-specific guidelines are expected in the coming weeks.

These will include reiterations of the widely-used thermal power plant guidelines, as well as guidelines for geothermal, oil and gas, mining and other types of infrastructure projects. The current draft guidelines were issued on August 2 for public comment. The IFC will accept comments on them until September 30. Copies of the draft guidelines can be obtained from that portion of the IFC website devoted to the EHS standard updates.

Superfund Liability

Recent court decisions reestablish the principle that parties forced to clean up contaminated sites can sue other responsible parties to share the cost of cleanup under Superfund.

Despite more than 25 years of court precedent and established practice, the liability scheme under the federal Superfund law (also known as CERCLA) was thrown into confusion by a Supreme Court decision that seemed to say responsible parties who avoid government enforcement by voluntarily cleaning up their properties cannot recover some of their costs from other responsible parties under Superfund.

The Supreme Court decision in *Cooper Industries v. Aviall* in 2004 held that only cleanup costs incurred under an enforcement proceeding or under a judicially- or administratively-approved settlement could be recovered in lawsuits between liable parties. Aviall Services bought contaminated property from Cooper */ continued page 46*

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and voluntarily cleaned it up under state supervision. Aviall sued Cooper to try to recoup a share of its remediation costs. The Supreme Court said that Superfund did not allow a claim in that situation, a decision that until recently appeared to have a chilling effect on Superfund litigation.

In July, a federal appeals court in New York issued its second consecutive post-Aviall decision affirming the right to bring private cost-sharing actions without waiting for the government to file a Superfund lawsuit. These decisions by the US appeals court for the second circuit, both of which involved only private parties, may also affect the outcome of a pending federal appeals court case in California, where the US government is defending against a cost recovery claim by arguing that Aviall precludes lawsuits against the government or any other liable party.

The appeals court for the second circuit is able to authorize these types of private claims because the Supreme Court decision in *Aviall* addresses a completely different section of Superfund than the one on which the newer cases are based. Under section 107 of Superfund, owners and operators (among others) of a contaminated property may be jointly, severally and strictly liable for the costs of investigating and cleaning up a release of hazardous substances, regardless of their culpability in causing or allowing the contamination. Section 113 of Superfund provides an explicit right of contribution for those liable parties to sue other parties for a share of the costs. *Aviall* held that those section 113 actions could not be brought by parties who failed to wait until they were forced to clean up the contamination pursuant to a government order or government settlement. However, the *Aviall* decision left open the question of whether the costs of voluntary cleanups could be recovered under section 107.

The *Aviall* decision was criticized as creating a disincentive for companies to clean up sites voluntarily without waiting for the government to sue. Cleanups under voluntary state brownfields remediation programs would not qualify as a "civil action" or "settlement" under the court's interpretation. It also would create delays in cleanups and increased costs associated with added governmental oversight as well as foreclose cost-recovery actions where the federal government is a responsible party. Although the *Aviall* decision did not affect contribution rights that exist under state statutes and common law, it ended a standard procedure for seeking recovery of cleanup costs from other responsible parties.

The new court decisions appear to be headed toward carving out a post-*Aviall* remedy for potentially-liable parties who have conducted voluntary cleanups or cleanups under administrative orders with the US Environmental Protection Agency or state environmental agencies to continue to be able to recover their costs under Superfund. The response to *Aviall* may prompt Congress to amend the Superfund statute to provide for an explicit right of contribution when a liable party conducts voluntary cleanup.

A Supreme Court decision this summer may force a reworking of federal wetlands and wastewater permitting programs.

Clean Water Act

A decision earlier this summer by the newly reconstituted Supreme Court led by Justice Roberts has created uncertainty about the reach of the federal Clean Water Act.

In the first environmental ruling by the Roberts court, a divided bench rejected the expansive jurisdictional reach currently employed by both the US Army Corps of Engineers and the Environmental Protection Agency. The court said the Clean Water Act does not regulate every ditch and intermittent waterway that might occasionally discharge into a navigable waterway or its adjacent wetlands, but it could not muster the consensus necessary to say exactly where the jurisdictional line should be drawn. The decision will force a reworking of current federal wetlands and possibly wastewater permitting programs.

Rapanos v. United States raised the question of when developers must seek permits to fill wetlands. The federal

Revised Equator Principles

In July, 40 international financial institutions announced newly-revised Equator principles that will govern their lending practices. Originally adopted in 2003, the principles are a common set of best practices to manage social and environmental risks related to project financing.

- The threshold for application of the principles has been lowered from project financings with capital costs above $50 million to all financings with capital costs above $10 million.
- The principles are also expected to cover upgrades or expansions of existing projects where the additional environmental or social impacts are significant.
- The principles have been streamlined for countries with existing high standards for environmental and social issues.
- Each participating institution will now be required to report on its progress in implementing the principles on an annual basis.
- An effort has been made to strengthen standards with the adoption of the new IFC guidelines and more extensive public consultation procedures.

government asserted jurisdiction over Michigan wetlands lying near ditches or man-made drains that eventually emptied into traditional navigable waters, where the existence of federal jurisdiction is clear.

Justice Scalia, joined by Justices Roberts, Alito and Thomas, argued the Clean Water Act should extend only to waters that are "relatively permanent, standing or continuously flowing" or to wetlands that are immediately adjacent to such waters. Four dissenting justices took the opposite view, leaving Justice Kennedy with the tie-breaking vote. Although Kennedy sided with the Scalia group against the government's position, he used a completely different standard for Clean Water Act jurisdiction, arguing that while there should be limits on Clean Water Act protections for remote water bodies, those with a "significant nexus" to navigable waters should be protected. He concluded that such a "nexus" could be established if the body of water in question significantly affects the integrity of navigable waters.

The Supreme Court ruling in *Rapanos* is likely to produce several important results. First, an increase in Clean Water Act-related litigation is likely. Second, lower courts will take on a significant new and somewhat unpredictable role in determining the parameters of the Clean Water Act. They are unlikely to develop a cohesive and universal interpretation of the statute. Third, the failure by the court to agree on the scope of the Clean Water Act in *Rapanos* may force the Army Corps to restrict the scope of its general wetlands permits. Finally, increased pressure has been put on the Environmental Protection Agency, the Army Corps and Congress to offer guidance regarding the scope of Clean Water Act permitting.

The US home building industry filed several challenges recently to force the Army Corps to update its regulatory definition of protected waters. In *NAHB v. US Army Corps of Engineers*, the National Association of Home Builders challenged the policy of the Philadelphia district office of the Corps of regulating ditches that eventually connect to navigable waters. Numerous courts have allowed Clean Water Act jurisdiction over wetlands based on their proximity to ditches that eventually connect to navigable waters. Should the district court rule in NAHB's favor, other courts could be forced to re-examine the issue.

The Environmental Protection Agency and the Corps have begun discussing how to reauthorize existing permits for construction and mining activities, and possibly issue new permits for other activities. The Corps recently announced that it will soon start the process of making changes to its nationwide permit program, which creates pre-approved general permits for certain activities that have minor impacts on wetlands. The revisions are expected to be issued in final form in early 2007 and implemented next March.

In addition, an internal memo distributed to Corps district officials last month says that the Corps and the EPA are in the process of developing joint guidance clarifying Clean Water Act jurisdiction following *Rapanos*. The memo stresses that any changes expected will focus on the tests and justifications the Corps uses when / *continued page 48*

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it makes its jurisdictional determinations rather than on the definition of "waters of the United States."

All of this uncertainty could prompt Congress to clarify which waters are subject to Clean Water Act protection. However, any such action is unlikely before the November elections because of the polarizing effect of environmental issues.

Greenhouse Gases

The Supreme Court has agreed to review whether the Environmental Protection Act must regulate greenhouse gases under the Clean Air Act. EPA argues it has no such obligation and would not do it anyway. The tendency by the current Supreme Court to interpret laws narrowly makes it unlikely the court will rule against the agency.

The case is *Massachusetts v. EPA*. It deals with those portions of the Clean Air Act that authorize EPA to regulate pollutants from motor vehicles, but the definitional issues could reach into federal stationary source air programs as well. Even so, the environmental ramifications of the decision are particularly acute given the fact that motor vehicle sources are responsible for more than a quarter of the US greenhouse gas emissions. The Supreme Court decision could also have important implications for the interpretation of US environmental laws. This will be the second time in a year that the court has had a chance to comment on the scope of US environmental statutes.

In the case, 12 states, three cities, an American territory and numerous environmental organizations petitioned EPA to regulate greenhouse gas emissions — carbon dioxide, methane, nitrous oxide and hydrofluorocarbons — from cars and trucks under the Clean Air Act. EPA declined, stating that it does not have statutory authority and, even if it does have authority, it would choose not to regulate greenhouse gas. A US appeals court upheld the EPA position. Although the specific issue in *Massachusetts* is limited to emissions by motor vehicles, a decision requiring regulation of vehicles would pave the way for related carbon dioxide programs. The outcome may also affect other pending lawsuits. In April, states, cities and environmental groups filed suit against EPA demanding that the agency place limits on carbon dioxide emission from new power plants and industrial facilities. That litigation may be suspended until the *Massachusetts* case is decided.

This would be the first decision by the US Supreme Court relating to global warming and the role of the federal government in regulating greenhouse gases. Greenhouse gases are already being regulated at the state and local level. The court could decide what level of government should regulate this field. Last month, California became the first state to adopt its own greenhouse gas emission limits for automobiles. Several other states have followed California and begun to regulate motor vehicle emissions. This has led to industry lawsuits. In California and 10 other states, automakers are opposing state emission standards for cars and trucks. ◎

— contributed by Andrew Giaccia, in Washington

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