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NewsWire

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The "End Game" For Merchant Power

Many merchant power companies in the United States appeared to be barely hanging on financially early in the year. Three are currently in bankruptcy. However, conditions improved enough by early summer for companies in the sector to be able to resume borrowing and to raise additional equity.

The outlook remains cloudy. The companies are highly leveraged with billions of dollars in loans coming due in the next three years. Almost all regions of the United States have more electric generating capacity than they need. This condition is expected to persist in many parts of the US until as late as 2010 to 2014, according to the latest forecasts from industry experts. Private equity funds are circling the power industry like vultures hoping to pick up projects at fire-sale prices. There have been fewer sales than expected. The banks — in no hurry to write off loans — have been allowing loans coming due this year to be refinanced, but the rollovers are short term and often come at a cost to the merchant power companies of having to put up better security, leaving less room for maneuver the next time. Meanwhile, the US economy as a whole is starting to improve.

Chadbourne hosted a debate in San Diego in June on the question, "What is the 'end game' for the merchant power industry?"

The following are excerpts from that debate. There were eight debaters, four to a side. Four spoke for the lending community. They are Leanne Bell, a / continued page 2

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PREPAID ELECTRICITY DEALS got a green light from the Internal Revenue Service on August 1.

The IRS issued new regulations that will allow owners of some power plants that supply electricity to municipal utilities to benefit indirectly from tax-exempt financing for their projects.

Gas suppliers are already able to enter into such arrangements. Roughly 20 prepayment deals have been done to date, mostly for gas. In gas transactions, a gas supplier enters into a long-term contract to supply gas to a municipal utility. The utility is given a discount in exchange for prepaying for the gas. It borrows the / continued page 3

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managing director of GE Structured Finance, Gail Nofsinger, vice president in the capital markets division of CoBank, a cooperative bank based in Denver that has been a lender to many merchant power projects, Larry Kellerman, a managing director with Goldman Sachs & Co., and William Chew, a managing director of Standard & Poor's.

The four debaters opposite were Tom Kilgore, vice president-structured finance with El Paso Energy Corporation, J. Stuart Ryan, until recently executive vice president and a chief operating officer of The AES Corporation, Donald R. Kendall, a leading investment banker in the 1980's who now manages a portfolio in the power sector for hedge funds at Carlson Capital, and Andrew Schroeder, vice president of the EIF Group, formerly known as the Energy Investors Funds.

The debaters alternated in laying out their views of the future and in prodding the other side. Other speakers include Mark Woodruff, president of the AES business unit with responsibility for the western part of North America, Kenneth Seplow, vice president of United American Energy, Adam Wenner, a regulatory lawyer with Chadbourne in Washington, and Michael Polsky, president of Invenergy, an independent power company in Chicago. The moderator was Rohit Chaudhry, a project finance lawyer in the Chadbourne office in Washington.

MS. BELL: In order to set the stage for my response to the end game, I thought it wise to tell you what we had in mind at GE Capital for the game at large.

GE Capital has an energy portfolio totaling almost $8 billion. We have called on many of you in the room looking for partners who share our view of long-term capacity and energy margins, partners who can manage day-to-day operations including dispatch, and partners who are attracted to our well-priced money. We look to invest equity in plants with long-term tolling agreements with investment-grade counterparties. As a structured equity provider, we rationalize giving away upside for downside protection.

Just as with most QFs we invested in long ago, we knew we were dependent on tollers. Our models suggested way too many plants were being built for the capacity values in the near term. Fortunately, we and many others in the room were aware of the mighty big difference between an integrated utility offtaker and a power marketing company.

It is the morning after the big party. Drained kegs and empty Dorito bags litter the floor of our collective house.

You may recall the experts once said that Exxon Mobil was a dinosaur that would cease to exist. Exxon Mobil lives on. However, our view internally is that the dinosaur appears to have been the framework around which we did business over the past few years.

Where do we go from here? With respect to us, we've made a business of buying QF equity in the nine to 10% after-tax range from sellers looking for liquidity — terms that we hope work only for us.

With respect to the market at large, I've come up with this hypothesis, and many of you may disagree with it, but here goes.

For the next year, most of us would probably agree that many gencos will continue to obtain 30-day default waivers and some will die. In time, those gencos that obtained the waivers will decide it is not worth working for lenders without the prospect of the near-term payoff and effectively turn the assets over to their lenders. Lenders secured by distressed assets will hold out for as long as possible hoping for relief in the capacity markets. Relief won't come and certainly won't come quickly. Reserve margins and gas prices will stay high, nukes will stay on, and the weather will stay rainy in New York.

Lenders will be forced by the regulators or managements to write down the assets. Sick of managing the power plants, these discounted assets will be offered for sale to aggregators of distressed assets looking for a 15%

return. Money will pour in. More and more aggregators will enter the fray, margins will be driven to dismal levels, driving the aggregators to sell their portfolios to investor-owned utilities. It will be cheaper to buy the assets and put them back into rate base than to remain subject to the volatility of the wholesale market. Reintegration will lead to fewer financially-healthy utilities. They will have a very highly efficient gas fleet but in all the wrong locations. These utilities will eventually be eliminated and power will become a fungible commodity across the United States.

This statement is somewhat controversial, but I'd be interested in my colleagues' responses to it.

MR. KILGORE: Thank you, Leanne. It is indeed refreshing to hear such happy optimism. The merchant model is dead. Long live the merchant model.

Let me address where we are, how we got here and where we're going to go. This paradigm lasted, what, five years?

Why did the paradigm arise? It arose out of several things. First, we are talking about a business that has a fundamental interaction between politics and the marketplace. And whenever the government enters business in a regulated environment, you find mass inefficiency. That mass inefficiency still characterizes the investor-owned utilities today, which is why the merchant model arose, why it died, and why it will come back again in a slightly reformed framework.

The underlying fuel for all this work on our part was firms from 1980 on engaged in a 20-year bull market propelled to grow at all costs and propelled by lenders desperate to put their capital to work at egregious premiums. These combined to erode the independent power industry. The non-regulated subsidiary companies and energy merchants all scrambled to grow and to claim a market share.

A whole paradigm developed around iron in the ground and megawatts under your control, a paradigm no less bankrupt than looking at internet companies and page views. We succumbed to that, too. How many of you still have dot com companies in your portfolio wondering when they will come back?

What we see in the future for the merchant energy sector is that we will have a new merchant sector, not in the manner described by my esteemed colleague, but rather because there is an inefficiency, and / continued page 4

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funds to cover the prepayment in the tax-exempt bond market. The effect is to give the gas supplier access indirectly to money at tax-exempt borrowing rates. IRS regulations allow a supplier who is prepaid for "goods" to report the prepayment over the same period the goods are delivered as long as this is how the income is reported for financial purposes.

These deals run afoul potentially of rules that bar a municipality from borrowing at tax-exempt rates and then reinvesting the proceeds in a commodity or other "investment-type property" that earns it a higher return than its cost to borrow. The discount off the gas price might be viewed as such an arbitrage profit.

In April 2002, the IRS proposed an exception to the arbitrage rules to allow prepaid gas deals. On August 1, the IRS modified the gas exception and also broadened it to cover electricity.

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

In prepaid gas deals, at least 90% of the gas must be used by the municipal utility to supply retail gas customers in its historic service territory or to generate electricity for customers whom it is required by federal or state law to serve.

The parties to long-term contracts usually also enter into a swap at the same time. Under the IRS regulations, such swaps are okay as long as they are with third parties and the swaps stand as independent contracts. / continued page 5

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because the regulated markets and their regulators have, in effect, outsourced to the merchant companies the bundling of services and the management of risk. That function has been lost from the investor-owned utilities.

As we go forward, as the companies involved today restructure, as we replace our managements and bring in management that understands VAR and how to apply it properly, as we apply proper credit policies and margining factors, and as we become more astute political players, you will see a new energy merchant arise, one that is able to function in this market. It will be a private rather than a public entity. It will be very well connected with the local regulatory system. It will arise on a regional as opposed to a national or global basis. That is the future of merchant energy.

MS. NOFSINGER: I'm surprised to hear you admit that there were things that you didn't tell us up front — like politics. Did I hear you say management didn't know what it was doing?

I think we will still have a merchant market. It is not a market to which the banks are eager to lend, but they will continue lending because they want to be repaid what was lent before.

We relied on everything you told us: your plans for the future, your plans to have the most megawatts in the ground, competitive power for everyone, and electricity prices that will remain high enough to allow you to repay your debts to us. It should probably have been obvious that one consequence of deregulation is prices fall. Where are all the consultants today whose forecasts suggested otherwise just two and three years ago?

One key assumption made by the banks is that if prices fell, eventually demand for electricity would increase. Plants would be dispatched with greater frequency. That has not happened, either.

At the end of the day, we remain committed to the merchant market. Painful lessons lead to greater understanding of how not to do things the next time. And we are going to get back the money we have already lent.

MR. RYAN: The merchant power companies will be here for some period of time, notwithstanding the severe liquidity crisis that all these companies faced about a year ago. What we now realize is that it wasn't a liquidity problem but a solvency problem for the most part.

Many people are predicting that the real crunch will come in 2006 or 2007, and merchant companies that refinanced today will be staring bankruptcy again in the face then. I do not believe the merchant companies will end up in bankruptcy. They were all tailored to be super-high-growth engines, but the same engines still work in coasting mode. There are plenty of places where the companies can find efficiencies within. In addition, the current interest rate environment is a strong wind at the back of those companies that will allow them to restructure and avoid bankruptcy.

Share prices for many of the companies have recovered to a point where they are again able to raise equity. The more equity they can raise, the farther the threat of bankruptcy recedes.

What will the future bring? I think we will have something other than a merchant energy business. I say that because "merchant" has become a loaded word. We will have a competitive power market principally because, at the end of day, it doesn't make sense to sell electricity to each member of a large varied group of customers at exactly the same price and terms. Each customer is different and deserves different terms.

What will happen to all the debt encumbering the merchant power companies? We will obviously see a lot less debt in the future. The mistake made was too much leverage. It doesn't require any sophisticated change in structure to fix — just less of it.

On the equity side, I see today many new entities looking for an opportunity to play. The equity money will be there, but there will be much more sophisticated analyses of commodity price risks, credit risks and regulatory risk. The hybrid model or partial deregulation is a dangerous cocktail. Regulatory risk is a huge problem when regulators are allowed to second guess capital investment decisions on an hourly basis. I do not see the muddled model or the model where everything goes back into rate base as at all likely given the preference in this country for competitive wholesale markets.

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MS. BELL: I think Stu Ryan just called me a muddle. Now I'm feeling a little cranky. I took exception to a lot of what you said, but the question that falls out, given the popularity of this concept of aggregators — these hedge funds and other companies that are forming with the intention of buying up assets at distressed prices over time — is how do you see those companies interacting with the El Pasos and maybe one or two others that might still be around after the year passes? Do you see any conflict between the two types of companies? Or do you see them working together?

MR. RYAN: I don't see the aggregators establishing a significant presence, to tell the truth, and I am someone who is spending most of his time in that space right now. My theory is that most of these companies — the would-be sellers of these assets — are not going to be major asset sellers. This leaves little room for aggregators. I do not think you will see the equity selling out like that.

MS. BELL: Think about this added twist to my theory. I was a lender for a very long time. The banks will hang on to these assets for as long as they possibly can. But the regulators will move in at some point and ask, "What the hell happened here? You're calling this a par investment? Your statements are suggesting that condition might hold for a while." At some point, the regulators will push the numbers down and the assets will end up with the aggregators or somebody else.

MR. RYAN: Depends on size, right? If it is a big enough lender problem, that may be right. If the problem does not rise to the level of $30 billion or so, then I don't see the regulators stepping in and forcing the banks' hands.

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MR. KILGORE: A question for Gail Nofsinger: wouldn't you agree with me that there is demand for a unique service and that there is a need for merchant power companies or someone else performing the same role to provide that unique service? It may be an aggregator who provides the service. It may be a Goldman Sachs. I think you would have to agree there is no better evidence of a new merchant model emerging than seeing Larry Kellerman, the quintessential developer, now working as an investment banker and employing money in the sector. Would you not have to agree with me that that is proof positive that the merchant model survives and that there is an ongoing need for management of electricity?

MS. NOFSINGER: Isn't the fact that Larry Kellerman is on the money side a sign that the lenders / *continued page 6*

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STAPLED STOCK can no longer be used to boost foreign tax credits.

US power companies that used such structures are assessing whether to unwind them. The IRS made an announcement in late July in Notice 2003-50.

The United States taxes American companies on worldwide income. It tries to prevent double taxation of income from foreign sources by allowing a credit in theory for any taxes that had to be paid to another country, but the foreign tax credit rules are so full of fine print that few American companies are able to claim such credits in practice.

One problem is the IRS treats a US company's borrowing costs at home — even for purely domestic purposes — as a cost partly of its foreign operations. A portion of this domestic interest expense is allocated to foreign operations in the same ratio as the company's assets are deployed at home and abroad. The effect is that a company is not viewed as having earned much money abroad after this allocated interest expense is subtracted. Smaller foreign earnings mean fewer foreign tax credits. In fact, most US power companies are in an "overall foreign loss" position, meaning that they have millions of dollars in allocated interest expense to burn off before they are viewed as having earned anything abroad.

Some US companies resort to self-help remedies. One such remedy was stapled stock. A US company might "staple" the shares of a foreign subsidiary to one of its US subsidiaries. This means that the shares of the two companies cannot be sold separately. It has the effect of subjecting the foreign subsidiary to US income taxes as if it were a standalone US company. The key word was *standalone*. Although the foreign subsidiary must pay US income taxes, it could calculate its own foreign tax credits unhindered by any / *continued page 7*

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are now the owners and they are merely trying to bring good talent to their side in the hope of getting out of the situation?

MR. KILGORE: But that doesn't answer the question. You may be owners now, but this is a marriage that is still intact. It may be an ugly and long divorce for so many parties involved, but it is still an intact union. And wouldn't you say that that union will survive in one form or another?

MS. NOFSINGER: Maybe we will stay together, but the question I have for you is: what will your motivation be when we are getting all the money out of it?

MR. KILGORE: You get to ask me questions later.

The industry moved from franchise monopolies to a competitive market. Business risk increases when that occurs and, yet, leverage increased sharply at the same time.

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MR. RYAN: Would the fine and proper Miss Bell please act out for the group just how she would explain to her credit committee that the assets will end up inevitably back in rate base where the potential returns are limited by regulation?

MS. BELL: We invest against contracted cash flows, so at the end of the day we will be making our —

MR. RYAN: You are supposed to be talking to your credit committee.

MS. BELL: I am talking to my credit committee. We invest against contracted cash flows. In round two, we will be a lot smarter about that counterparty with whom we are dealing. In round one, we bought a whole lot of bunk with respect to risk management procedures, and we bought a whole lot of bunk about limits and controls that will not, I think, stand the test of time.

MR. RYAN: How are you going to get to a contract risk as opposed to a regulatory risk in the market you see developing in the future?

MS. BELL: Let me be very clear about the answer here. We are going to our credit committee and we are saying we know the future — I am the creditor, and you are the credit committee — we know the future. The future is expected to be X, and it is a controlled environment but one in which we can make a return over time. It will not be a high return, but it is a stable return.

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MS. NOFSINGER: Mr. Kilgore, before we make a decision about separation, what is it you are planning to bring to the table that will allow the marriage to remain intact?

MR. KILGORE: Well, flowers and chocolate have always worked well for me. [Laughter.]

MS. NOFSINGER: That worked the first time around, but the banks are not buying it.

MR. KILGORE: I'm tempted to think about jewelry, but —

MS. NOFSINGER: You are limited to a $500 gift.

MR. KILGORE: We'll have to work backwards, then. I think the answer is rather simple. We will bring to the table, as current developers, enough expertise to be able to try recovering some return of our equity and return on our equity. It is unlikely for any developer to stay with a project once he determines that he cannot get either a return of or return on equity. And he will return the project rightfully to the lenders. That leaves the lenders in the merchant energy business. And a group of lenders that apparently failed in its original due diligence — having made an issue of it with us — now gets not only to repeat the mistake of that due diligence, but now has to operate that facility in the absence of people with historical background and expertise to help. That's the foreseeable outcome. It is really a transfer one project at a time or one small project company at a time of the merchant model from the original developers and entrepreneurs to the lending community.

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MR. KELLERMAN: On behalf of the lending community, I want to start off by saying *mea culpa*. We on the lending side have created an egregious error and a major sin by being too lenient, by being too tolerant of the wayward paths of the developer community.

Thus far in this debate, we have heard much about the destabilizing effects of hubris and benign tolerance for an unsustainable business model that has brought this industry to the precipice of ruin. What we have to do is point out and reconcile ourselves to, perhaps, the role that the parties most culpable had in the creation and perpetuation of this sad state of affairs in our industry. Unfortunately, I have to point to ourselves in the commercial lending community as being the perpetuator of the problem.

In the criminal justice system in this fine country of ours, the purveyors of elicit drugs are meted out much, much harsher punishments than the hapless and wayward drug abusers. I point out to you in the audience, the hapless and wayward drug abusers [*Ed*. The speaker is pointing at the opposing debaters who are representing project developers] who have been on the side of the street unfortunately being given the crack cocaine of liberally-granted funds by ourselves on the lending community. [Laughter.] That must stop. In the halls of this industry, we should likewise be placing due blame and opprobrium where it belongs on the parties who have lavishly dolled out the funds that have been responsible for this industry's demise.

Thinly-capitalized developers and larger merchant energy firms have become this sector's junkies. Junkies motivated and, yes, actually rewarded by weak lenders via the cocaine of liberally-available project financing against assets that have no power contracts and very little chance of ever getting a power contract.

Just listen to these numbers: 45, 44, 41, 40. No, these are not the respective IQs of the poor hapless debaters opposite. [Laughter.] No, these are the projected 2004 summer reserve margins in the SPP, ERCOT, SERC and MAIN respectively. On the hottest day next year, verily, there will be more than 40% more metal in the ground in these regions than could possibly be used. And nationally that figure is a bloated 34%.

The fundamental cause of this great waste of capital and destruction of value in our industry is that somebody gave these misguided souls a weapon of */ continued page 8*

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allocated interest expense from its US parent company.

The IRS said in July that it will require in the future that stapled foreign companies take into account allocated interest expense. The new policy applies to foreign companies that are newly stapled to US companies after July 22, 2003. It will not apply to companies that were already stapled on July 22 until after the current tax year ends, giving US multinationals time to unravel existing structures.

Meanwhile, the IRS is challenging some existing stapled stock structures on audit. It said that it will continue to assert on audit that stock was not effectively stapled where there was nothing to prevent the US parent from breaking the staple at will.

TRANSMISSION CREDITS will be addressed by next June, the IRS said.

Independent generators pay the cost of connecting their power plants to the local utility grid. This is the only way to get their electricity to market. Interconnection usually involves constructing not only a radial line to hook into the grid, but also improvements to the grid so that it can accommodate output from another power plant.

On July 23, the Federal Energy Regulatory Commission adopted a model interconnection agreement that all generators and utilities will be expected to use in the future. Under this agreement, utilities will be allowed to ask generators to advance money for grid improvements — called "network upgrades" — but the utilities must repay the advances within five years with interest. FERC said the cost of network upgrades is more appropriately borne by all users of the grid rather than individual generators. Some utilities, like Entergy, had already been awarding generators "transmission credits" that they can work off */ continued page 9*

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mass economic destruction, and that weapon was cheap, highly available capital without a disciplined diligence process effectively to constrain these poor souls from misapplying that capital. That is our fault, and it is something that we on the lending side should stop. [Laughter.]

But alas, now it is 2003, the morning after the big party. Drained kegs and empty Dorito bags litter the floor of our collective house. [Laughter.]

The lenders have woken up and discovered that their homes are filled with marginally conscious, blurry-eyed developer revelers from the night before. They don't smell very good, and you have to watch where you step. [Laughter.]

What should a responsible lender do in a circumstance like this? You clean up the mess, and you send the junkies packing.

But what are we in the lending community doing? This is the dilemma facing my colleagues today. The lending world by and large continues to funnel money, resources, and most of all, benign tolerance for an unsustainable business model. By not forcing a radical set of changes on this merchant energy sector, what we are doing is condoning and perpetuating a folly that spark spreads will rebound, and that the good old frat house days will return once again. They are not coming back. And by not forcing a fundamental change in perspective, we are lengthening the time during which we do not have the three R's that need to take place in this industry: restructuring, recapitalization and renewal. By putting that day off, we are perpetuating the problem.

This industry is mired in malaise and plagued by procrastination. Poorly-capitalized, non-investment-grade credits cannot prosper in the merchant sector. Lenders need to reconcile themselves to the fact that a poor credit cannot perform adequate risk management, cannot properly hedge its positions, and cannot optimize its assets.

Lenders to this industry, I call upon you to realize the gravity of our collective problem and to transition troubled assets in your portfolios out of the hands of those misguided souls in the marketplace who have misapplied the funds and so fool-heartedly taken those assets and sub-optimized them even to this day. [Applause.]

MR. KENDALL: Thanks for ruining my talk. [Laughter.] I wanted to say first that I'm really on both sides or neither side. As a relatively new entity, Carlson Capital fortunately does not have the past baggage of problems that almost everybody else here has. I also want to review some of the history. This is a relatively new industry. We really didn't get started until the Public Utility Regulatory Policies Act, or PURPA, was enacted in 1978. We really didn't have a merchant business until the 1990's. So the industry is still in its infancy.

Also, the amount of value destruction that has occurred is just gigantic. If you go back to January 2001, the market capitalization of the top 10 players was a little over $200 billion. If you go back a little bit earlier this year, the combined market capitalization of the same top 10 players was about $25 billion. The market destruction on the debt side is probably more significant than on the equity side. So, clearly, many, many mistakes have been made.

Very few bankruptcies have occurred so far, but also very few problems have been solved. I think we are merely deferring the problem until 2005, 2006 or 2007. It will be a fun and interesting world when we get up to that point in time.

We are in a new world. This is a commodity business. We have moved from a regulated framework where you did not have the risk we have today to a world where you have part deregulation, part regulation, and you are subject to ups and downs and the supply and demand issues of the normal commodity business. We do have very high fixed costs. We do have many technical issues. It is not easy to store electricity. Transmission requires a lot more technical expertise than is required to deliver groceries and other similar services. Add to this the fact that companies in this business have operated with very high leverage.

We have had a huge number of bad business models. Some of those I think can be changed. Some will have to be destroyed and the companies start over again. I agree with Larry Kellerman that there was far too much cheap capital. I have talked to a number of developers who said lenders forced them to take money. In my view, both sides are to blame because, yes, the developers are taking what is cheap, but they did not identify something rational to do with it.

We are about to see some major changes with the entry of new players. There are probably as many ex-El Paso people here as Chadbourne people, but probably only two or three of them are still with El Paso. This is typical of the shift in the industry. In the future, attendees at these types of meetings will be from a host of new entrants.

A couple things are worth noting about the new world. We will have dramatically modified behavior. A few years ago, generating growth and trading volume was the focus. Today, the focus is much more substance over form. By that, I mean let's do trading where it is profitable and not just to create volume so that the company can be ranked number one.

You are also going to see a huge decrease in the attempts at manipulation. Handcuffs work. We will see more prosecutions in other areas where there has been fraud. We will see major migration toward trading platforms. There will be improved price transparency. There will be better ways to understand where the risks are and are not in the business. There will be much more attention paid to price and credit risks. Many painful lessons have been learned from the current debacle.

History should be studied because it can repeat itself. Fortunately I wasn't involved in it, but one of the early failures in this industry that hit a number of players in this room was the AES Deepwater project. It was done as a very high-capital-cost-project because of a relatively low-cost petroleum coke fuel. The contracts did not match. Their base was dependent on gas prices remaining high. My recollection is that GE Capital's gas forecast at that time said gas would never fall below $4 again. Before the project completed construction, I believe gas was under $2. And before GE funded its lease equity commitment, the project was in default.

Those things will happen time and time again. It is a simple lesson in project finance 101. You need to make sure that the revenue and expenses match and that people work to mitigate risks.

MR. CHEW: It seems I'm in the midst of role reversals. My colleague has said all the lenders are wrong. It sounds to me like my opponent just said that the developers are wrong.

At the risk of muddling the issue further, let me go back to at least a couple of the questions that were asked and give a perspective from Standard & Poor's.

What is the end game? I agree with what Mr. Kilgore said: the merchant model is dead. Where I disagree is whether the lessons have been learned. There are two issues we see in particular. First, what was the / continued page 10

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against future wheeling charges or receive back in cash. FERC has also ordered some utilities to repay amounts they collected in the past from generators for network upgrades, even though the utility had not promised the generator a refund when the parties signed their interconnection agreement.

Utilities want the Internal Revenue Service to confirm that they do not have to report advances from generators for network upgrades as taxable income.

The IRS issued one private ruling to that effect in late February, but then stopped issuing any further such rulings. It has "10 or 12" ruling requests stuck in the queue, according to an IRS official. The problem is not necessarily that the IRS believes utilities have income — the generators insist they are merely lending money to the utilities — but rather that anything the IRS says on the issue might come back to haunt it in other areas of the tax law. The IRS says it generally refrains from ruling on whether arrangements are loans.

The power industry met with senior IRS and Treasury officials about the issue in July, and the issue has now been put on the latest IRS business plan. The IRS commits each July to a list of issues that it will address in the coming year. The industry hopes this one will be addressed soon. Some generators have large tax deposits or letters of credit tied up with utilities pending resolution of the issue.

In a related development, the Federal Energy Regulatory Commission ordered the New England Power Company to drop its demand that AES post security to ensure payment of any future taxes that might be triggered on the electric intertie for the Londonderry project in New Hampshire. Under US tax rules, a utility should not ordinarily have to pay taxes on interconnection payments from an independent generator that the utility is / continued page 11

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problem? A lot of it has been the failure of the business model. However, we believe that the business model is only part of the failure. The real wreckage — the real source of value destruction — is the matching of a weak and, in fact, very risky business model with very high-risk finance strategy. There was an increase in leverage at exactly the point that the business risk was increasing. Look, we moved from franchise monopoly markets to competitive markets. Business risk automatically increases when that occurs and, somehow, we have leverage increasing sharply at the same time.

I am not sure from listening to the comments from the chastened developers on the other side and from my lending colleagues that this lesson has been learned. Yes, you have heard the call for lower leverage. I think the real lesson is that the leverage must match the specific business risk that is still contained in some of the reconstructed business models we have seen.

Second, another lesson that remains to be learned is the big challenge is dealing with some of the compound credit risks that are embedded in the merchant model even today in the firms that remain in trouble. The problem is there is a basic conflict in the trading model that is embedded in these firms. Trading requires enormous capital. At the same time, it creates additional exposure to credit risk.

It has been unclear to us for some time how the aggressive trading models can be maintained while the credit ratings at best for some of these operators are low investment grade. We look at the financial derivatives market, which is the closest thing to the financial trading that is taking place here. In that market, the counterparty credit for transactions is high investment grade or else the trades involve a structured derivatives product operation that protects against losses when the market turns sour.

Just to finish addressing all the questions, I think this sector will be able to attract new capital, but it will be on a risk adjusted basis. There will be a true risk adjustment on the pure merchant model. The debt component needs to be *de minimus* in order to continue to attract equity investors. The problem with enthusiastic lenders will remain. The animal keeps choosing to play, as we heard in the discussion yesterday about the debt market reopening to further borrowing by merchant companies that were in distress just three months ago. That may indeed occur, but to be sustained over the long term, the companies will require much higher equity.

> Private equity funds will come in with an early 15% after-tax return and then ultimately decide that it is only 10% and want out.

Finally, we have the question of whether the industry will remain plagued by asymmetric returns. I think the problem is excess capacity. It is not simply the return that is the problem. It is driven by the phenomenon that we have a lot of springing potential additional capacity that will come into play at exactly the wrong time. When we move from a regulated model to a competitive model, we often forget that the constraints on additional capacity that were supplied by certificates of need were supposedly replaced by the economics of the marginal cost barriers to entry. The difficulty here is that the marginal entry is off of a rate-based utility that does not respond in any sense to market incentives. Indeed, the utilities have the incentive to run additional rate base just at the level sufficient to drive the merchants down to very difficult prices. So over the long term, we expect there will be a real problem in avoiding boom and bust in this sector as long as we have a hybrid arrangement.

MR. SCHROEDER: As a current equity investor in this space and a recovering lender, I have reached step three in the five stages of working through loss. I see a bleak future for the merchant power business and merchant lenders.

I think that a false optimism has set in recently after some of the energy merchants and independent power producers restructured their debts. The restructurings were nothing more than a full employment act for the lenders and for others involved in our business. Sweeping the problems under the rug for the next three or four years is not going to solve this crisis. It will only put it off.

The industry has more than $80 billion in debt that must be refinanced in the next six years. You have higher rating agency thresholds, some of which are egregious. You have deals that are coming into the market today with ultra-conservative structures. This is a hard way to finance future growth of this business. The energy merchants have given up their flexibility by pledging all their remaining collateral to get the recent refinancings accomplished.

As we heard yesterday, the companies and the banks are reluctant to take writedowns of assets. That will only hurt them down the road. You are not going to see many sales, if any, of merchant assets in the near future. Anyone wanting to buy into the business must face the fact that this is a business with huge credit needs and heavy working capital requirements. The standard market design proposals by the Federal Energy Regulatory Commission remain a huge open question. Yet, without standard market design, the future outlook for merchants remains questionable. There is a new gas pricing environment that will bring increased volatility for players going forward. There will also be some shocks to the system from additional bankruptcies.

The bottom line is I think the financial hangover will continue for at least another three to five years. The only way new plants will be financed is with a back-to-the-basics strategy. As Bob Cushman suggested yesterday, perhaps we will be back here in 2008 wondering why this merchant quagmire has not gone away.

* * *

MR. KELLERMAN: My question for the Right Honorable Mr. Schroeder is why, in your opinion, should we lenders not seize any opportunity — actual default, technical default — presented by developers to foreclose on the outstanding loans and take ownership of these assets? Then, at least we will have control over the destiny of those assets going forward.

MR. SCHROEDER: A couple comments: first, I think you probably should, but banks are reluctant to do that in some cases because they do not want to take the writedowns that go with it. Second, some of these assets are not going to be rescued no matter who owns them. / continued page 12

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allowed to keep. However, it is possible for a tax to be triggered in certain circumstances in the future. AES agreed to indemnify the utility for any such future taxes. The utility also wanted AES to post security to ensure payment of the indemnity. FERC said in an order issued on June 27 that the utility could not require the security.

In another development, the IRS said in a private ruling made public in June that a tax is not triggered in the future merely because the power plant lost its status as a "qualifying facility," or QF. The ruling is PLR 200324037.

SYNFUEL PROJECTS hit more turbulence.

The IRS has scheduled a meeting with tax counsel who have been working on synfuel projects for August 14 in Houston. At last count, 15 such projects are under audit by the IRS, and there are indications the agency is considering disallowing tax credits that the owners of the projects have claimed as far back as 1998.

The US government allows a tax credit of $1.095 an mmBtu for making synthetic fuel from coal. The IRS has issued more than 80 private rulings confirming that coal agglomeration facilities — plants that add chemical reagents to coal — make synthetic fuel. However, in late April, it stopped issuing any further rulings. In late June, it announced that it has "reason to question the scientific validity of the test procedures and results" that the companies that own these plants submitted when they applied for rulings. The agency is considering whether to revoke some or all of the rulings.

At the meeting in Houston in mid-August, Bobby Scott — the head of the IRS audit team — is expected to explain what the agency is attempting to verify in the audits and answer questions. He has set aside two hours for the / continued page 13

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I am not sure the banks will do any better job managing the problem than the current owners. In fact, taking control of the assets creates regulatory problems that many banks would probably just as soon avoid.

* * *

MR. KENDALL: Perhaps the only parties who seem to have been more wrong than the developers and the banks are the rating agencies. How did they miss the paradigm shift in fundamentals? What is Standard & Poor's doing about it in terms of being a predictor of credits rather than a reactor to credit changes?

MR. CHEW: I knew it was a danger exposing our end of the business to a parliamentary debate. [Laughter.] For that very reason, I think I will dare not speak for the rating agencies.

Interestingly enough, in fact we did hammer home a number of these issues for merchant projects, and that is one of the reasons why we rated virtually none of these projects. Our requirements, we were told seven or eight years ago when we put out our first paper on the subject, were absolutely outrageous in terms of our projections for price decline and in terms of the limits we wanted on leverage. We were just out of the market. In fact, the lenders, we were told, were just delighted to lend at much higher levels of leverage and much lower levels of coverage.

Obviously, there are things we missed, but on the fundamental issue of merchant project finance, I would argue that Standard & Poor's was very much on target.

* * *

MR. SCHROEDER: Larry Kellerman, given the lack of creditworthiness of the counterparties in the merchant power business, do you think there is an opportunity for players like the big oil companies, Goldman Sachs, Morgan Stanley and others with big balance sheets to fill the void, take some risks and make some money? And do you think the risk for them is worth the return given the failure of some former blue-chip names who thought they were appropriately skilled to take those risks?

MR. KELLERMAN: There are not enough of us around to fill that void, and the reason is because there has been such a huge amount of overbilling. When you have reserve margins the way they are today, there is a great trepidation to step into the merchant space. That point notwithstanding, what you really need in order to optimize a merchant asset is a trading floor and the willingness to do proper risk management around that asset.

There is a growing handful of firms — Wall Street firms and some of the other larger integrated energy companies — that do still have an appetite and for whom trading is not a four letter word. That's very important as the entire merchant sector has moved out of trading because the merchants have done a really bad job of it. It isn't that trading is a bad thing. It is that merchant energy traders, most of whom have been centered in Houston, have done an awful job at trading. Those who can do a good job of trading — who tend to be centered more around the periphery of New York than around the 610 loop — have done, historically, a much better job of trading. And those, frankly, are the natural owners of assets for which you need trading to optimize value.

Therefore, I agree with you that either Wall Street firms, financial institutions, or large integrated energy companies are the right owners of those assets. There just are not enough of them around to solve the problem in whole.

MR. SCHROEDER: That answer scares me. I have heard the same point from some of your former colleagues at El Paso and others in the trading business. I am not sure that, just because you are in the trading business and are based New York City, you are in a better position to take on the risk without the customer base for the commodity.

MR. KELLERMAN: A firm like Goldman Sachs has been trading for over a century. We actually do it fairly well. Other firms that got into this business several years ago did not have the controls, did not have the systems, did not have the right grounding and management. People above me at Goldman Sachs understand trading. I don't want to talk about my former employer, but there are very few in top management in the merchant energy space who really understand trading.

* * *

MR. WOODRUFF: This question is for Larry Kellerman. Why would a company like Goldman Sachs or any other trading organization need to own or control power plant assets if it chooses to speculate on commodity prices? And second, this talk of "managing or trading around the assets," doesn't it blur the distinction between speculation on commodity prices, on the one hand, and the fundamental engineering and operational aspects of managing the assets, on the other?

MR. KELLERMAN: Good questions. The answer to the first question is the reason that a firm like Goldman Sachs and a number of other financial firms that are represented here today are interested in the asset space is because we don't speculate. Speculation has been a hallmark of a number of the activities of merchant energy firms. Firms like Goldman Sachs and other firms manage risks, but they do not speculate. They do not take major long or short positions without having those positions effectively hedged. The electric power business, unlike a number of other businesses around which trading occurs, has a very, very strong physical component. And to be an active player in the traded markets in electric power means that one should not ignore the physical aspects of those markets, so that what a firm like Goldman Sachs sees is very strong synergy.

Trading can amplify the returns otherwise available from a power plant that is devoid of a trading capability. An asset can be put into an environment where that asset can be risk managed even if it is a contracted asset, where one has optionality in fuels, where one has optionality between generating or supplying the power by buying it elsewhere in the market. Those values can best be perceived in both forward markets and in real times where one has the integration between both the physical plant and a trading floor.

One of the key values that trading provides in any marketplace is the unleashing of the embedded optionality resident within positions. That can be done in a financial sense through extracting optionality, through trading derivatives around the product that exists. When one has a physical plant that offers different added forms of optionality in the form of "I can run, I cannot run, I can use A fuel or B fuel, I can sell to this market or that market based on my transmission interconnections." That only amplifies the financial optionality that already is resident within a good solid trading floor and expands the number of options, the number of different parts that the trading floor can exploit.

I'm not trying to be too encompassing, but we've seen it on our trading floor. Goldman saw it with the Orion experience, which was a very positive one for / continued page 14

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meeting. The agency hopes to start wrapping up the audits this fall.

The government is concerned about the potential impact on the utility industry if tax credits are disallowed. DTE said in a press release that 70% of earnings from its unregulated business unit are linked to nine synfuel plants. Progress Energy said in a press release that it has claimed $447 million in tax credits on its five synfuel plants and is carrying forward approximately another $500 million in unused credits.

A showdown meeting between the industry and top Treasury and IRS officials in July has not yet produced the result the industry wanted. Treasury officials continue to insist that this is strictly an audit issue. The industry argues that it is unfair, after taxpayers relied on so many rulings to make large investments, for the government suddenly to reverse course.

DEPRECIATION BONUS regulations are still on track to be issued by September 9.

Meanwhile, the IRS released a "technical advice memorandum" in June that may help some companies argue that they should get a depreciation bonus.

The United States is offering companies the chance to write off at least 30% of the cost of new plant and equipment immediately as an inducement to invest. This is a limited-time offer that applies to new equipment put into service during a "window period" that runs from September 11, 2001 through 2004 or 2005, depending on the investment. Congress increased the bonus to 50% for investments after May 5 this year in the hope of spurring even more investment.

A company cannot have committed to the investment before the start of the window period. For most power projects, this mean that construction cannot have started on the project before September 11, 2001. Custom-designed projects / continued page 15

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Goldman obviously having gone out at the right time, but it is also seeing the current environment as a good opportunity to be able to buy the right assets at the right price.

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MR. WENNER: This question is for Leanne Bell. The US government — through the Federal Energy Regulatory Commission — is pressuring the industry to keep generation separated from transmission and distribution functions. Indeed, Bob Mitchell from Trans-Elect said yesterday that there are additional basis points for his transmission company because it is only engaged in transmission and, were it to become a generation owner or affiliate, it would lose that benefit. There is also an issue that arises when one tries to put a merchant plant back into rate base. It goes in at the depreciated original cost, meaning that the returns might not be so juicy. How does this fit with your view that all the assets are headed eventually back into the rate base?

MS. BELL: Have we paid all our Chadbourne bills I guess is what it's coming down to. [Laughter.]

We absolutely are participating right now in a vacuum and making as much money as we possibly can. I stand by my view. I will be around in 20 years because it may take that long to play out. But I actually do believe that over time this business is going to aggregate. Folks like Don Kendall will be part of the process against folks like Tom Kilgore over time. The aggregators will take all the fun out of whatever game we play in the next couple of years. They will come in with an early 15% after-tax return and then ultimately decide that it really is only 10%. And that is when you create an opportunity for the investor-owned utilities again. They grab these assets, get the returns, make the case to their regulators, and we're back to a different, but somewhat similar game to the original mess. I stand by the point.

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MR. SEPLOW: Gail Nofsinger expressed strongly the views that banks should take possession of these assets they have lent against, and I have no doubt that Gail and other bankers will act on that at some point in the future. Once you get these assets, what will you do with them? How will you manage them? How will you liquidate the value in those assets in order to pay off your loans?

MS. NOFSINGER: None of the banks really wants to own the assets. Ultimately we want to get our money back that we lent. To the extent that we can work together with the developers in the troubled projects to get out, we certainly would prefer that. It is a question of whether the sponsor is still creditworthy. Does it have the ability to put more equity in? Is there a way to get us through this situation? If we do end up owning the assets, there are lots of capable operators who can be hired on a contract basis. Years ago, I used to lend to the waste energy business and lent in recycling, and I thought I had better not lend to this plant unless I want to be there picking the garbage off the conveyer. I feel like I am in that position today. I really do not want to be operating the power plant. I do not look good in a hard hat.

MR. SEPLOW: Can I ask Don Kendall, as someone who has been buying up debt of distressed projects, through what process will you realize the value that turns a nice profit on your investment?

MR. KENDALL: Unfortunately for us, or perhaps fortunately, what has happened is the high-yield bond funds have way too much money right now. If you look at our portfolio, the average price of bonds was in the 80's when we bought. Almost all of them are returning at par or above today. How we are getting out is by selling the debt to the

> The mass inefficiency that characterizes the regulated utilities is why the merchant model arose, why it died, and why it will come back again.

dollar investors and the high-yield bond funds. We do not see rational value at the prices at which the bonds are trading at today. So we will be doing more liquid things. Basically, we are buying something that is liquid so we can trade out of it. We are also trying to make sure we have done enough homework so if we are stuck with it, we know we can hold the debt and clip the coupons while it is being paid on a current basis or else be comfortable enough should we have to foreclose that there is economic value in doing so.

* * *

MS. BELL: Don Kendall, how do you manage to take over an asset and outsource the dispatching function and the O&M function where you're outsourcing to two separate entities? How do you anticipate managing that process? Do you go to a toller and then go to an operator and they're different without losing some synergy in the middle?

MR. KENDALL: Clearly, I think what the banks are focused on today is the O&M side. There are many people who will contract the O&M. What I think the banks are missing, and we have not solved it yet, is the risk management function. I don't know whether Larry Kellerman at Goldman Sachs will be willing to provide that service to third parties. I have had three groups approach me wanting funding to start up a risk management business to run the banks' assets.

MS. BELL: Will they also handle the O&M function, or will the banks still have to find a separate operator?

MR. KENDALL: Each bank situation is different, but my view is the banks will step in on some of the energy projects. It is easy to find a contract operator. It is not easy to find someone to handle the risk management side. At least that is our judgment so far. One of the reasons we are not buying distressed assets yet to control plants is I don't know what I am going to do with a plant once I own it. If it is a contracted plant, it is reasonably easy, but you still want to optimize around the contract. Someone here may have solved the problem, but I don't think many people have.

MR. KILGORE: Can there really be a third-party market for the risk management function? Isn't there a conflict issue? Larry Kellerman is so good at this stuff. If he was marketing the output for your bank, isn't there a risk that he would run it for his position and not yours? It would be impossible to sort that out.

MR. KELLERMAN: You're right. It is */ continued page 16*

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like power plants are considered "self constructed."

The technical advice memorandum in June involved a utility that wanted to qualify in the late 1980's for an investment tax credit on its spending on 35 separate work orders for things like substation upgrades and customer hookups. In order to qualify for work the utility was doing itself — or "self constructing" — the utility had to show it had committed or incurred at least $1 million or 5% of the total project cost by December 1985. The IRS concluded in the technical advice memorandum that these were 35 separate projects. Therefore, the utility could not pool the costs to meet the dollar threshold.

This helps with the depreciation bonus because, even if one "project" was tainted due to work having started before September 11, 2001, other projects may not have been.

A technical advice memorandum is a ruling by the IRS national office to settle a dispute between a taxpayer and an IRS agent stemming from an audit. The ruling is TAM 200324003.

SOME INVESTMENT FUNDS will have to find a new structure for tapping into money from pension trusts after an IRS ruling in late July.

The IRS issued two rulings about different forms of variable annuity contracts that an investor might purchase from a life insurance company. The product is called a *variable* annuity because the eventual annuity paid is linked to the return the insurance company earns from investing the premium paid by the investor. The investor has a choice of different accounts or investments he can direct the insurance company to make. He can also move the money between accounts.

The issue the rulings address is whether the investor should be */ continued page 17*

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very difficult for any trading company to put a box around a given asset and say this is the asset, and I am only going to trade around that asset. It is hard to disentangle oneself. Whenever we have been approached with that kind of opportunity, we have said simply that we will give you a price. Let's say there is a distressed combined-cycle gas-fired plant. We will say, name the period of time that you want to get this off of your system, and we will buy the tolling off of it. It may not be as good a number as you would like, but we will give you a good, solid, reasonable bid-sized offer, and we will take it off your hands and give you revenues for one year, two years, whatever period of liquidity you require. But when someone asks us to trade around an asset for him, that appears too ridden with conflict, and we have not figured out how to do it.

* * *

MR. CHAUDHRY: What is the road map, if there is a road map, for merchant companies to become solvent again?

MR. KILGORE: That's a very good question, and I think it really depends on the nature of the merchant energy company, or former merchant company in our case. Having lost many great people to other institutions, we made merchant energy a non-core business segment and have been liquidating it rapidly since then. To return to best status, I think, one, we need to sell assets prudently. Two, there are sustained higher prices for basic commodities right now. We may not see it in electricity right now, but we certainly are seeing it in gas and fuel commodities. That gives us earnings power to return. Companies need to clean up the balance-sheet confusion by getting rid of mezzanine levels of capital. This is not something that will happen on a real-time basis, but rather over a period of at least a year or two. For some companies, it will take longer. Finally, you continue to argue your case vigorously in front of the rating agencies that just because they were slow in catching the knife on the way down doesn't mean we need to be perpetually put in the basement until things move forward. We do that, and it is often well received if not quickly acted upon.

MR. CHEW: It may seem like the plummet that happened overnight, but the forces that generated it gathered over time. It will take some time to work out of the current situation. The asset sales and de-leveraging of the capital structure are key points. One other point is the need to get back to real, recurring operating cash flow. An awful lot of what passes for cash flow in this industry is still financing activity. You have to wash that out and get back to basic ratios.

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MR. POLSKY: There are a lot of businesses similar to power plants — conversion businesses where you take one commodity and convert it to another one, and you get a final product. I might argue that a power plant is no different than a refinery. However, there is a tendency to view them like mines. Everybody thought that if they built a power plant, somehow they would create inherent value as if they placed a commodity in the ground — sparks in the ground.

Here is my question. Why isn't a power plant just a broken business and until you create a business, there is no value there? Why do the banks feel that by simply locking the door on the power plant, it becomes worth more three, four or five years from now? Where does it say that a business with a lock on its door becomes more valuable three years from now than it is today?

MS. NOFSINGER: I don't think the banks want to close down the power plants. We want to get our money back. I'm not involved in any plants where we have actually locked the doors.

MR. POLSKY: But why do you feel that in three years, it will be worth more than it is today?

MS. NOFSINGER: The consultant reports. At some point, the power could be valuable. Maybe today it is not.

MR. POLSKY: The point I'm trying to make is the power plant is just a conversion place. It is not like owning gas in the ground. With power plants, you have to buy inputs, you have to convert, you have to structure the business properly, you have to produce outputs, and you have to decide how you sell output. Just because the electricity price is going up does not mean the power plant has value.

MS. NOFSINGER: I guess our point is we are looking for cash flow, and if it is costing us more to run it than to shut it down, why would we run it? At some point, the banks will sell it for a loss and take a writeoff. ◎

"Dash Six Liability" Problems In Deals

by Keith Martin and Samuel R. Kwon, in Washington

Concerns about "dash six liability" are cropping up in many project sales and foreclosures this year. There are things the purchaser of a project can do in practice to protect himself, but the options are limited.

What?

Many power plants have been put up for sale in the last year and a half since Enron went bankrupt. Some lenders have been handed the keys to projects that are under construction. It is usually easier when taking over a project to buy or foreclose on the shares in the special-purpose company that was set up to own the project. This saves having to have all the contracts, permits and other rights tied to the project individually assigned or transferred to a new entity.

Business people know instinctively that there is danger in taking over an existing company. The company may have run up liabilities. Buyers do due diligence — or investigate carefully — to make sure there are no such liabilities. They also get representations and indemnities from the seller.

"Dash six liability" is often present and is potentially a large number.

Most corporations in the United States file "consolidated" or group income tax returns at the federal level. A parent company files a single return for itself and its domestic subsidiaries — at least its domestic subsidiaries that are treated as corporations for US tax purposes and that it owns at least 80% by both vote and value. (Mexican and Canadian subsidiaries may be included in a US consolidated return in some circumstances.)

The Internal Revenue Service can hold each corporation that is included on a consolidated return accountable for the *full* taxes that should have been paid by the group in the event there is shortfall. This liability is called "dash six liability" because it is discussed in the IRS regulations at section 1.1502-6. A project company that was part of a consolidated return is exposed for group taxes for all years that it was included in the consolidated return. IRS regulations say that if a subsidiary has left the group by the time the IRS comes after it, then the IRS "may" */ continued page 18*

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treated as the direct owner of the investments. They conclude that he should if — among other things — the investments were available for direct purchase by the general public and there is little diversification of investments in the segregated asset accounts set up by the insurance company. For example, Revenue Ruling 2003-92 addresses a case where an insurance company set up various segregated asset accounts each one of which holds an interest in a single partnership. The partnership interests can be purchased by any accredited investor through private placements. The IRS said that, even though the *partnerships* make diversified investments, that is not enough since the investor is using the insurance company to make an investment in a single partnership in which he could have invested directly.

Investment funds sometimes try to tap into money in pension trusts. Pension trusts are exempted from US income taxes, but must pay taxes on any "unrelated business taxable income." Dividends, interest, royalties, annuities and some other types of passive income are not considered such income. Therefore, the investment funds sometimes arrange for pension trusts to invest in them through an annuity contract that earns a return tied to the investment results in the fund. Such arrangements will be harder to make work after the latest IRS rulings.

MINNESOTA enacted a renewable portfolio standard.

Starting in 2005, at least 1% of retail electric sales by each utility in the state must come from wind farms, small hydroelectric facilities, solar, hydrogen or biomass fuels. The percentage will increase by 1% a year until 2015. Meanwhile, the Public Utilities Commission is expected to set up a program of tradable credits. */ continued page 19*

Dash Six Liability

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limit its claim to the share of taxes that the subsidiary contributed to the group return. However, there is no obligation on the IRS to agree to such a limit.

Dash six liability is present when buying shares in a corporation. It is not ordinarily present when buying a partnership interest or when buying a membership interest in a limited liability company that is treated for tax purposes as a partnership or "disregarded entity."

There may be similar exposure for state income taxes. Corporations sometimes file combined or group returns at the state level. Some state regulations provide explicitly for "joint and several" liability of each subsidiary for the full taxes that should have been paid on the group return.

Some project sales have been called off this year due to fears about dash six liabilities.

Practical Issues

The IRS can only reach the subsidiary's assets — not other assets of the buyer group — but only as long as the subsidiary remains a separate corporation. Thus, for example, if Corporation A buys the shares in Corporation B, the IRS has a claim only against B. It does not have a claim against A as B's new parent company.

A would be wise not to liquidate B into itself or merge A with another subsidiary that has substantial assets. The dash six liability will carry over to the merged company.

How often does the IRS pursue subsidiaries that have left the group in practice for group taxes? Probably not frequently, but there is no ready data on this. Lawyers at the Justice Department who pursue tax claims said that it is "not the norm" for the government to start with a subsidiary that has left the group. It will try to collect first from the remaining members of the group as a "first option, second option, third option." However, the government will do what it must to collect if its collection efforts against the other group members are stymied. If the deconsolidated company has "lots of cash," the government might go after it more readily than it would if it owned a factory because "the IRS does not want a factory, it wants cash," a government lawyer said. State laws that make it easier for the IRS to collect might play a role. It is a "practical decision," another government lawyer said. It depends on "who is doing the collection. The IRS has thousands of collection agents, and they all have different ways of doing things."

> Concerns about "dash six liability" are cropping up in many project sales and foreclosures this year.

Options?

The best way to avoid dash six liability is to buy or foreclose on assets and not shares in a corporation. The liability does not follow the assets where the assets were sold for fair market value, according to Ted Zink, a bankruptcy partner with Chadbourne in New York. Zink said that when a bank forecloses on assets, it should also get the assets free from dash six liability.

Questions about whether liability attaches involve issues of both tax law and creditors' rights. The IRS regulations give the government a claim against a corporation for taxes. When and against whom the government can pursue the claim is a question of law on creditors' rights. The government is like any other creditor.

Sometimes shares in a corporation are sold but the parties make a "section 338(h)(10) election" to treat the transaction for tax purposes as if it was an asset sale. This does not shed the dash six liability.

A buyer who has no alternative but to purchase shares should get an indemnity from the seller for any dash six liability. It is customary for this indemnity to last for six months after the so-called limitations period for the IRS to bring claims for back taxes against the seller consolidated group. The statute of limitations against back tax assessments usually runs three years, but large corporations routinely extend the limitations period, and it is not unusual to find tax years still open for assessment for five or six years — sometimes longer.

The indemnity might not be very creditworthy. A buyer might ask for security. He might ask for a perfected lien on some of the seller's assets. In theory, he might hold back part of the sales price, but this is impractical given the amount of time that would have to pass before the issue disappears.

It is hard during due diligence to assess the potential exposure. A buyer might take some comfort if the seller group has been losing money for several years because the odds are reduced that it owed any taxes. (On the other hand, the seller may have had more reason to cut corners.)

It is a good idea to close any share purchase transaction that is pushing up against the end of the seller group's tax year before the year ends rather than let it slip into the first few days of the next year. A subsidiary is liable for the group taxes for the full tax year, even though it was included in the seller's consolidated return only for the first few days of the year.

Dash six liability is not ordinarily a concern when buying a foreign company. For example, suppose the project company being sold was formed under Mexican law and is not included in the seller's consolidated US tax return. The IRS would not have a claim against the project company for group taxes. Dash six liability only extends to corporations that were part of a US consolidated return.

There can be a benefit to buying shares in a bankruptcy proceeding. In such a proceeding, the bankruptcy court has the ability to determine whether the IRS has a claim against any of the bankrupt entities for taxes before letting the subsidiary go. The buyer would be wise to get the judge to address the issue of any outstanding tax claims. Once the issue of what taxes are owed is decided by the bankruptcy court, it cannot be reopened by the IRS. However, since only some entities in a consolidated group may be thrown into bankruptcy, unless the parent company that files the consolidated return were also part of the bankruptcy proceeding, dash six liability would not be foreclosed.

Buyers with no choice but to buy shares have considered asking the seller to convert a corporation into a "disregarded" limited liability company or partnership before the sale. This would spare the buyer from having to buy shares in a corporation. Whether this technique sheds the liability depends on the state law under which */ continued page 20*

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Utilities will be able to satisfy the requirement that they supply a certain percentage of electricity from renewable sources by buying credits from independent generators who use renewable fuels.

The credits will be tradable in neighboring states that adopt renewable portfolio standards that are similar to the new standard in Minnesota.

ILLINOIS will now subject self-help gas that is purchased out of state and imported into Illinois for use there to a gas excise tax of 2.4¢ per "therm" or, if less, 5% of the purchase price for the gas. Such gas had been exempted from the tax. A "therm" is 100,000 Btus.

MICHIGAN may hold buyers of whole businesses accountable for income taxes that the seller failed to pay for the year of sale.

Michigan imposes a "single business tax" on companies doing business in the state. Each company files an annual return. The tax is 1.9% of gross income from Michigan sources. In 1993, a company bought a McDonald's restaurant from another corporation. The seller filed a single business tax return for 1993 two years after the sale, but failed to pay the full tax shown. The state tried for two years to collect, but gave up after discovering the responsible parties had moved to Mexico. It then went after the buyer for the unpaid tax.

A Michigan appeals court confirmed in July that the state can collect the tax from the buyer.

The Michigan statute requires anyone buying a going business to make sure the seller paid his single business taxes for the year of sale. The seller must file a single business tax return within 15 days after selling his business. The buyer must pay the sales price into escrow */ continued page 21*

Dash Six Liability

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the conversion takes place. For example, the Delaware corporate statute that governs conversions of corporations into LLCs does not say explicitly that liabilities are inherited by the LLC, unlike the Delaware statute that governs mergers of one corporation into another, but careful corporate lawyers advise that one should assume the liabilities will be inherited.

Anyone buying an LLC or partnership interest should confirm during due diligence that the project company is not a converted corporation.

Another question asked periodically of tax counsel is whether a buyer of shares in a target corporation can limit his exposure by closing first on the share purchase and then stripping the assets from the target through an intercompany sale to one of the buyer's other subsidiaries. The answer is this does limit the exposure, provided full value is paid and there is no deemed merger of the two subsidiaries. If the target then distributes the cash to the common parent, the IRS might be able to have the distribution clawed back if it were viewed as an unlawful or excessive dividend or a fraudulent transfer under the relevant state law. Some state laws limit the period of time that a distribution is at risk of being reversed. ◎

Sales of Distressed Assets

Chadbourne hosts an annual conference for top people in the independent power industry. The conference this year was in June in San Diego. One of the panel discussions focused on the market for distressed projects. Many people had thought early in the year that there would be opportunities to buy power plants at fire-sale prices, but there has been a smaller number of sales than expected. The question before the panel was, "A new popular wisdom is taking hold that there will be fewer opportunities to acquire distressed power projects than thought earlier because the banks are in no hurry to write off bad debts. What's the truth?"

The speakers are Jay Beatty, a prominent investment banker with long experience in the utility sector and who is currently managing director of New Harbor in New York, Robert Cushman, who has been looking for distressed assets in his role as vice president for mergers, acquisitions and structured finance at Entergy Corporation, Glen Davis, who held various senior positions with The AES Corporation and was most recently group manager of a team that was working on selling assets, Karl Miller, a senior partner with Miller McConville Christen Hutchison & Waffel, LLC, a private power company that formed last year to buy distressed assets, and John Schuster, the chief business person at the US Export-Import Bank for lending to projects in the power sector. Mary Power, a vice president for project finance lending with the German bank DZ Bank in New York, and Mark Woodruff, president of the AES business unit with responsibility for the western part of North America, asked questions. Keith Martin, a Chadbourne partner and editor of the NewsWire, *was the moderator for the session.*

MR. MARTIN: Jay Beatty, it now looks like there will be fewer project sales this year in the power industry than people had thought earlier –- perhaps as few as 10 or 12 large transactions. Do you share this perception of the market?

MR. BEATTY: There has been an extraordinary shift in the market just in the last three months. Both project-level debt and corporate debt are now trading at two to four times the levels in March. That means that the liquidity crunch is essentially over for now, and companies can raise money in ways that were unimaginable earlier this year.

MR. MARTIN: So the pressure has eased to sell assets?

MR. BEATTY: Right. I had a meeting earlier this week with a client who had just finished a major strategic review of its assets with an eye to what can be sold to raise cash. The goal when the review started had been to shed as much as possible. However, by the time the review was completed, the conclusion was that everything is now strategic. I think you are going to see a lot fewer asset sales as people are not forced to raise liquidity. It is hard to imagine a credit in the industry that cannot clear the debt market at 80%.

MR. MARTIN: Bob Cushman, do you agree?

MR. CUSHMAN: Jay is right. Things are changing. A lot of it has to do with the resistance of companies and banks to take losses. Many people figure that if they could just hang in two, three or four years, things will come back, and there will be no need to take a loss. Stock prices have already collapsed. For a company to lay a new set of surprises on the market –- "Oh, by the way, we forgot to tell you that we have a large number of assets that should have been written off" –- it is just not going to happen.

MR. MARTIN: Glen Davis, your view?

MR. DAVIS: That sounds right. However, keep in mind that there are two types of assets –- contracted assets and merchant assets –- and there is also a hybrid class of assets that are partly contracted. [*Ed.:* A "contracted" asset is a power plant whose electricity has been committed under contract to a purchaser, usually over a long term.] The hybrid class contains assets where the contract is with an entity that is no longer creditworthy or has made a strategic decision to get out of the business of tolling or trading power. The transactions you may see in the next year or so may be driven mainly by strategic decisions of purchasers who want out of the business or by the unwinding of contracts with electricity purchasers who are no longer creditworthy.

Merely Delayed?

MR. MARTIN: Karl Miller, you have been a critic of merchant power companies and banks who think they can avoid losses by riding out the business cycle. You have suggested that the merchant companies have unsustainable capital structures and that a day of reckoning will come –- if not now, then two years from now. Jay Beatty said the market has turned around in the last few months to a point where most merchant power companies are again able to raise new money. Is it possible that any further huge selloff of assets has been not merely postponed, but also avoided?

MR. MILLER: I spoke recently at a conference in New York attended by bankers, and the theme was hope is not a strategy. A variation on that theme is hope is not your best friend. I agree with Jay that liquidity may have been easy to find within these irrational spreads fixed in the market. However, the long-term problem has not been cured. The reality is this market is going to see other assets change hands. A rational person might put some additional capital into these companies, but any such capital would be short term.

MR. MARTIN: Jay Beatty, how long can the banks avoid taking losses? How long can they roll over debt in the hope that market conditions will improve?

MR. BEATTY: I'm not sure. Right now, banks are rolling over debt, but they are rolling it over by taking / continued page 22

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until the seller produces a certificate from the state tax department confirming that the seller paid his single business taxes in full.

Otherwise, the law makes the buyer "personably liable" for the seller's gross income taxes for the year of sale up to the fair market value of the business he purchased. The case is S.T.C. Inc v. Michigan Department of Treasury.

LOUISIANA confirmed that equipment leasing is a way to avoid a tax on capital stock.

Louisiana requires every company doing business in the state to pay an annual tax on its capital stock. A company's capital stock includes its "borrowed capital," meaning any debts that mature more than a year after the date incurred or that are not in fact repaid within a year. The tax is $3 for every $1,000 in capital.

The state tax department insisted that a company that leased three fuel oil storage facilities and two boats for transporting fuel oil had to include the rents it expected to pay over the lease term as part of its "borrowed capital." It argued the lease was a financing.

An appeals court disagreed. The court said the leases were "true leases," and that they might have had to be included in borrowed capital if the lessee had a nominal purchase option at the end of the lease term, but the lessee in this case had no such option.

It also said that no debt arises for rent under a true lease until the rent comes due. Rents were due at six-month intervals. The case is System Fuels Inc. v. Kennedy.

UNITARY BUSINESSES are exposed potentially to more taxes at the state level. An appeals court decision in July in Massachusetts sheds / continued page 23

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better security. From the bank standpoint, this is a no-lose bet. If its borrower went into a bankruptcy proceeding today, the loan is non-accruing and the bank is stuck. If the bank takes better security and the borrower files for a bankruptcy a year from now, then the bank is in much better shape. So I don't think the banks have decided that their borrowers might be able to ride out the business cycle. The banks have concluded that if these loans are non-performing anyway, they are a lot better off if they are secured lenders than not secured lenders.

MR. MARTIN: John Schuster, does what we heard about the US market also sound true for foreign projects?

MR. SCHUSTER: There are two points. First, you are starting with a much smaller base of merchant assets in the emerging markets in which the US Export-Import Bank deals than in the US market. Second, the turnover of assets in these markets is likely to be even slower than in the US. Remember that you are often dealing with official lenders who are not going to be in a hurry to sell things off. There is less tendency to try to turn things over to new borrowers because part of what the lenders hoped they were getting was somebody with experience dealing with the government of Indonesia, for example. Turning the project over to a new, less experienced borrower is not a risk that the lenders will want to take.

Five Stages of Loss

MR. MARTIN: Before we got started this morning, you said that a banker goes through five stages before concluding that a borrower won't be able to repay a loan. What are they?

MR. SCHUSTER: This picks up on something that Bob Cushman said earlier. He said both banks and borrowers are reluctant to write off assets. They must work first through the classic five stages of dealing with a loss – you know, denial, anger, bargaining, depression — where you realize this can't go on forever — and finally acceptance. Eventually what happens is banks conclude they have no choice but to accept the new breakdown. I think that is eventually where the market is headed, but, as far as I can see, the banks are still in denial today.

The problem with private equity funds as owners of merchant assets is they have cash, but lack the credit required to trade electricity.

MR. MARTIN: When it comes to projects in *emerging markets*, the banks are still in denial?

MR. SCHUSTER: I think the problems are less acute internationally than they are in the US market. Maybe I'm just an international banker who is in denial.

MR. CUSHMAN: Actually, I have had some personal experience going through the five steps. There were several merchant plants in the UK in trouble. At the end of the day, there was a deep-seated belief by the bankers that if they didn't take the assets or restructure the debt, then someone like Goldman Sachs would come pick their pockets and, three or four years from now, Goldman would get rich and the bankers would look foolish. Therefore, the banks ended up taking a number of the assets. I am not sure that is how things will play out in the US. What we are seeing in the US is the rolling over of debt with the consequence that someone else is allowed to handle the problem. However, the banks are in a much more secure position with their US assets than they were in the UK.

Role for Private Equity?

MR. MARTIN: Thank you for that bridge back to the US market. In the US, many private equity funds are circling power industry assets like vultures. Is there a role for them if fewer assets than expected are put up for sale? Karl Miller?

MR. MILLER: There is a role for alternative capital in this market, irrespective of winning the collateral. The reality is the power industry must find new sources of capital. The capital will be in tiers. Some distressed asset funds might step into various pieces of the capital structure. Some might offer short-term financing in the worst cases. Others may come in with medium-term capital plus a moderate spread and with very solid asset security. And then you have the longer-term products. I will say this: they are not coming in for 30% rates of return. Return expectations are markedly down. That number is not realistic.

MR. BEATTY: The problem with private equity funds as owners of merchant assets is: how does the private equity fund trade the power? The private equity funds may have lots and lots of cash, but they are really bad credits. Are the funds willing to post the collateral required by counterparties to trading contracts? Interestingly, when NRG went into this, the first thing it did was get $250 million in debtor-in-possession – or DIP — financing. It needed that much money solely to allow it to trade its portfolio. Notice, it had all these existing lenders and it needed another $250 million in cash simply to trade. The cash does nothing except support trades. The private equity funds must ask how much additional collateral they are willing to post to be able to play in something other than the day-ahead market.

MR. CUSHMAN: Back to two distinct classes of assets: we have contracted assets that I think everybody recognizes are a game of competing discount rates, and we have merchant plants. Merchant plants are a much more difficult problem. There is no good solution to the merchant plant problem other than buying an option.

MR. MARTIN: Let's fill in a little background information. Of the 62 project sales or sets of sales last year, 60 were contracted assets, or plants that come with long-term contracts to sell the output. Bob Cushman, your point is that all you are doing when you buy one of those is purchasing an annuity or income stream. Only two of the projects sold last year were merchant plants.

Jay Beatty, your point is that private equity funds will find it hard to own merchant plants because one needs credit as well as cash to trade electricity. The funds have cash, but they lack credit.

MR. BEATTY: That's exactly right.

MR. MILLER: There is a hard question whether the credit required to do this business is justified, regardless of whether it is private equity or anybody else. It may turn out that the regulatory outcome is what is most important here. Before deregulation, credit resided in the public utility commissions. People did deals because / continued page 24

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light on how to avoid unitary treatment.

Massachusetts wanted to collect $1.2 million in corporate excise taxes from W.R. Grace & Co. on its capital gains from the sale of interests in the Herman's sporting goods chain, El Torito restaurants, and other businesses. Grace is a Connecticut corporation, but it does business in all 50 states. Massachusetts taxes any company doing business in the state on its income from Massachusetts sources. A portion of the company's entire income is allocated to Massachusetts in the same ratio as its sales, employees and property in the state.

The appellate tax board said the capital gains had too little connection to Massachusetts for the state to be allowed under the US constitution to tax them. However, such a connection would be present if the subsidiaries that Grace sold were merely components in a larger, "unitary" W.R. Grace & Co. business. In that case, the capital gains would be taken into account as income of the unitary business in applying the three-factor allocation formula.

On appeal to a Massachusetts appeals court, the court considered whether Grace and the subsidiaries were a unitary business. It said no for the Herman's and El Torito chains, but sent the case back to the appellate tax board to look more closely at the facts surrounding other subsidiaries. The court's opinion runs through a list of factors that are key to avoiding unitary treatment. The case is *W.R. Grace & Co. v. Commissioner of Revenue*.

POLAND is expected to cut the corporate income tax rate from 27% to 19% and to increase the withholding tax on dividends from 15% to 19%. The changes will take effect on January 1, 2004. The government has endorsed them, but they must still be approved by parliament.

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they knew that public utility commissions would allow them to cover all the costs in the end.

If the credit pressure on non-regulated entities is so great that the only way to keep this going is to return to a situation where only the regulated utilities can bring credit to the deal, then merchant plants — whether by contract or through ownership — are going to end up back in the regulated system. For the regulated utilities part, they prefer to buy the asset rather than do a contract. The assets will gravitate ultimately toward the regulated utilities.

The End Game

MR. MARTIN: Do you think that is the end game for merchant power –- all the assets will end up back in the rate base?

MR. MILLER: I don't think you can make a broad statement like that. You can't even make a broad statement about the direction in which regulation will take in this country. It varies from state to state. But I think you will see a move in the direction where assets end up back in the rate base.

MR. MARTIN: Come back to the issue of whether the merchant power companies are fooling themselves. The banks are letting them ride along for a few years. Are the current debt restructurings merely postponing the real day of reckoning two years from now when the merchant power companies will have to face up to their unsustainable capital structures?

MR. DAVIS: I think the first step for the banks that have made loans at the holding company or corporate level is to gain better security over the underlying assets of their borrowers. That is what you are seeing happening today. Second time around starting a year and a half, two years, three years from now, depending on the particular company, when these debts that have been rolled over come due again, the companies will again face the question whether they can pay their debts. If you don't see a future recovery of the market, the second time around the banks will exercise their security more than they have done to date. At the project level, it's probably a similar pattern. The banks will probably wait a year or two years, but probably not longer than that.

The rating agencies are requiring utilities that have committed to long-term power purchases to put part of the obligation on their balance sheets as if it were debt.

MR. BEATTY: I see the banks facing the same problem the companies face when they take over the assets. If the banks take the assets, what do they do with them? You see this question today with PG&E National Energy Group, which has turned over the keys to some of its power plants to its lenders. Will the banks sell the assets? If they hold on them, how do they manage these merchant assets? That will be the interesting test for a whole series of companies whose debts are coming due over the next 18 to 24 months.

On the other hand, given this capital market, I would not be surprised if merchant power companies are able to raise enough money to clear out this bank debt by replacing it with capital markets debt on three, five or seven year terms.

MR. MARTIN: Bob Cushman, you said something interesting before we started the session today. Entergy is both selling and buying assets at the same time. It is not the case that we have distressed companies shedding assets and a separate group of private equity funds and healthier companies looking to buy.

MR. CUSHMAN: But to a great degree, Entergy is always the buyer and seller on everything. It is just a matter of where we are and where we would like to be. We sell in markets that we believe have reached their potential, and we buy in markets where we think we have a better future. This is a matter of repositioning the company to focus on certain markets.

MR. MARTIN: And how is Entergy trying to reposition itself?

MR. CUSHMAN: Obviously, we have a nuclear strategy. We have been buying up nuclear assets. We also have a fairly aggressive trading arm, and in regional markets where our traders would like to trade, we will look at buying assets. But will we buy merchant assets? I really don't think so. We are in the same position as everybody else. No want wants to repeat the same mistakes the industry made in the recent past. Looking for contracted assets is probably the name of the game, but if you can't find something that works from a discounted return basis, then you move on.

MR. MARTIN: Karl Miller, how do you win a bid for contracted assets? What is the key?

MR. MILLER: We are not really interested in contracted assets; we are not going to compete on discount rate. That is just not our strategy.

Let me return to a point that I think Jay Beatty made. I think smart capital will always attract itself to the right deal. It is an integrated process. This is not a black-and-white market in which merchant power companies try to survive the business cycle for the next two or three years and then, all of a sudden, the market has to face up to the problem with capital structures. This will be an ongoing process. To date, the main opportunities for people to put capital into the sector have been at the holding company level rather than at the asset level. In the longer term, the assets will be up for grabs. You have seen a lot of contracted assets move but you have just not seeing merchant plants.

MR. MARTIN: Glen Davis, what is the best way to win a bid for contracted assets?

MR. DAVIS: Some people say the way to win when you are bidding for contracted assets is not to come in first.

MR. MARTIN: Why is that?

MR. DAVIS: The winner always loses.

MR. MARTIN: Cambridge Energy Research Associates did an exercise several years ago where it put a jar of pennies on a table and asked the audience to guess how many pennies were in the jar. There may have been $15 worth, but of course the winning bidder guessed $17 or $18. It is the person who buys the next time around — after the jar has been opened and the pennies counted — who does better. But one would think a bidder can already tell the number of pennies in the jar when it comes to a contracted asset.

If the bidding on contracted assets comes down to the cost of capital and competing discount rates, then what about merchant assets? Many people */ continued page 26*

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LEASE STRIPPING TRANSACTIONS do not work, the IRS said.

In a lease strip, the taxable income from use of an asset is separated from the depreciation deductions. The income is given to someone who does not pay US income taxes. The depreciation is kept by the US taxpayer.

The IRS explained a number of ways it plans to attack such transactions in a notice at the end of July. It also designated lease stripping arrangements as "listed transactions," meaning that arrangers must report any deals to the IRS as tax shelters and taxpayers who participate in them must disclose the details. The announcement is Notice 2003-55.

The IRS also insisted in a separate announcement in late July that section 482 of the US tax code can be invoked to reallocate income between parties to a transaction even though they are not related. Section 482 gives the IRS broad authority to reallocate income and deductions between parties who are "owned or controlled directly or indirectly by the same interests." The IRS said the fact that two or more taxpayers acted "in concert or with a common goal or purpose" may be enough to invoke the section. However, it said it would not resort to the section in lease stripping transactions because two taxpayers do not automatically "act in concert" just because they did a deal together. The conclusion is in Revenue Ruling 2003-96.

Norwest and Comdisco lost a lease stripping case in a US appeals court in June in a complicated cross-border transaction involving use of a partnership. The US tax court agreed with the IRS last year that the parties were not really partners since there was no substance to the transaction other than creation of tax benefits. The taxpayers failed to get the decision set aside on appeal. The case is Andantech L.L.C. v. Commissioner. */ continued page 27*

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have ascribed little value to them. Jay Beatty said in an earlier session that owning a merchant asset is the economic equivalent of SARS. Is there a sensible strategy for pursuing these?

MR. DAVIS: It is a case-by-case situation. The value turns on the region where the merchant plant is located, the local supply and demand outlook for electricity, the availability of transmission and how locational marginal pricing works on the regional grid for relieving congestion.

MR. MARTIN: Stop there for a moment. Explain locational marginal pricing and why it is important.

MR. DAVIS: It adjusts the price that a generator will receive for its electricity depending on whether the generator is supplying power into a regional grid at a point where the electricity is needed.

MR. MARTIN: What does this mean for a power plant that is, say, in northern Maine far away from consumers who use the electricity?

MR. DAVIS: What locational pricing does is it rewards the generator in Boston so that the Boston power plant is more likely to run. The Maine plant will shut down. The effect is to relieve some congestion on the transmission grid. Relieving congestion is worth money to the system, and that money goes to the Boston generator.

Rectangles *v.* Triangles

MR. MARTIN: Jay Beatty, you made the point at our last roundtable that the trouble with the merchant power companies is they are all making rectangles when the market wants triangles and this provides an opening for new players in the merchant power market. Explain this please.

MR. BEATTY: The notion is that a merchant power company is looking for someone ideally to buy 100 kilowatts every hour of the year from its plant. But what the market really wants is shaped power. What any load-serving entity that might buy from a merchant power company wants is a peak load, a minimum load, and mobility within the peak periods. Clearly the way to make money is to be the person selling that shaped power, the power the load-serving entities want and not simply offering a unit power contract for a 150-megawatt gas plant.

The more we believe the banks will become operators and traders in this industry, the more I am looking forward to the 2008 conference when we will be talking again about distressed assets.

The problem for the merchant power companies is becoming more acute now that the rating agencies are taking the position that load-serving entities that have committed to long-term power purchases must put a good portion of the obligation — in some cases 7% of the present value of the contract, which is a big number — on their balance sheets as if it were a debt.

This creates two problems. One is it may hurt the ratings of the electricity purchaser. This, in turn, hurts the merchant power company because a tumbling rating for the offtaker hurts the project. This has the effect of pushing load-serving entities — at least those who face the capital markets — to shorter-term purchase contracts — not of the 10- or 15-year variety, but of the 3-, 5- or 7-year variety. You are going to find load-serving entities pushing harder to buy shaped power rather than signing on to bulk contracts.

MR. MILLER: Let me put this discussion about shaped power into another context. What the merchant power company should be trying to do is to enhance or create value in the asset. The power company is focusing in restructuring talks in how it can come up with the funds to do this. I hope that the banks are thinking exactly the opposite. They are thinking about how they can do it. They see a hole in the revenue needed to support the debt. They are thinking about how to plug that gap.

MR. CUSHMAN: You know, the more we believe the banks are going to become operators and traders in this industry, the more I'm looking forward to the 2008 conference when we will be talking once again about distressed assets.

MS. POWER: I would just like to say something on behalf of the banks. First, in connection with the refinancing of unsecured assets by taking collateral, in most of those instances it been done on the basis that it gives the company time to make asset sales and repay the loan. One of the first companies to restructure has already paid 50% of the debt down and will eventually get to the point where the loan is manageable.

Second, in regard to taking title to assets, I am personally involved, on behalf of DZ Bank, in taking title to five merchant plants. This has been done in each instance on a very thought-out and careful basis. We have independent market studies of what the asset is worth and what we can recover. We have looked at putting people in to manage the assets, and we have one of the top companies managing those energy sales. The point is the banks are not going to be selling energy. They are putting people in to do it and run these projects until the time comes when we can sell and recoup our debt. Maybe we won't recover 100% of our debt, but we will recover more of it than we could have recovered had there been a sale now. And that's all we are trying to do. We have so much exposure in this industry. We have to maximize our recovery. We are moving as cautiously as possible.

MR. MARTIN: John Schuster, at which the five stages of loss is she?

MR. SCHUSTER: I'm impressed that this is actually getting beyond the anger and everything else and moving to the acceptance stage. Kudos.

MR. MARTIN: So the story here is that with the debt markets reopening to merchant power companies and the banks not in a hurry to push assets on to the market at fire-sale prices, the huge asset sales that were expected will not occur, at least in the short term?

MR. MILLER: Let me comment on what Mary Power just said. It is not the most efficient approach to deal with the assets one at a time by hiring experts to handle fuel procurement, power marketing, operations and maintenance, engineering. You can probably put somebody on top of all the outside experts as a bankers representative, but the model is not ideal. It leads to value deprivation. The better way to create value is to bring together portfolios of assets.

Asset sales will occur. I think portfolio sales will occur, and I don't believe that we will a see big gap for two or three years during which there are / continued page 28

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MINOR MEMOS: Congress is expected this fall to repeal a tax break for US exporters called the "foreign sales corporation" and to replace it with other corporate tax benefits. Repeal of the FSC provision will give it at least $50 billion to spend. Among the ideas under consideration is allowing US multinationals that are holding income outside the US tax net in offshore corporations a one-year window to repatriate the income to the US at a reduced tax rate . . . A US appeals court said that a gas pipeline company could depreciate gas gathering lines that take gas from the field to a central pipeline over seven years for tax purposes, even though the rest of the pipeline must be depreciated over 15 years. This is the latest in a series of conflicting court decisions on the issue. The cases are important because they might open the door for some equipment at power plants — for example, baghouses that trap fly ash — to be depreciated more quickly than the rest of the power plant. The case is *Saginaw Bay Pipeline Co. v. United States*. The court released its decision on July 30.

— contributed by Keith Martin and Samuel R. Kwon in Washington.

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relatively few asset sales. These assets will change hands.

MR. MARTIN: Glen Davis?

MR. DAVIS: I agree with the point that what is being transacted isn't really assets. It is businesses. And whether a standalone merchant asset can constitute a business is a key question. It can't be. One needs the ability to manage power sales as part of an integrated business.

Can a merchant asset, without being part of a portfolio and without being part of a trading platform, really be spun into some kind of business? One of the reasons the transactions in merchant assets haven't happened yet in volume is people are not able to define what the business is in many instances. Why buy such an asset? It is not a standalone business. And with so many people fleeing the trading business, it takes special courage for someone to move toward setting up the integrated model required to own such assets.

MR. BEATTY: That's exactly right. The contracted and the non-contracted assets are two very different businesses. With contracted power plants, it's a financial game with discount rates and financial engineering. With a merchant power plant, you are in the business of selling power. The fact of the matter is your business is selling electricity and you own assets simply to support that business. You must figure out your business model first, who your customers are, what business you want to be in, and then go in search of assets to support that business.

One of the more interesting shifts in the market in the past month or two is that, with merchant power companies able to borrow again, people are dropping strategic planning. Every asset they have fits. Now, that can't be right. It is like everybody being above average. If you really have a business plan, you are like Entergy. You have some plants do no longer fit the business plan, and other holes where you want to buy them.

I am not suggesting that one business is better than the other. I understand that some people may find the greatest attraction simply in earning a three or three-and-a-half percent or whatever compounded return on invested capital. That is a perfectly acceptable business model. But the fact of the matter is someone who buys contracted assets is getting into a very different business than someone who buys a merchant asset. One is a financing business and the other is a power business, and the two businesses require very different capital structures. The capital structure has to match whichever business model has been chosen.

MR. WOODRUFF: I have a question for Karl Miller about the value of the portfolio. Do you see a greater value of a portfolio of assets within a given regional transmission organization, or do you see greater value of a portfolio of assets that cuts across multiple markets? And why?

MR. MILLER: We're looking at both. We tend to individualize assets and then look at how can we, from a cost structure, optimize around those assets. We would argue that you could probably do a distressed portfolio and start a strategy in ERCOT and even in California. Outside of those two areas, I would say you're going to have to take a stand on geographic disbursement by having assets spread across markets to diversify risk.

MR. MARTIN: Let me leave this group with a quote. This is from the current issue of *Power Finance & Risk*. It seems particularly appropriate given that we started off this session with an observation that things have started looking up for merchant power companies in the last month or two — at least some of them are in a position once again to borrow. "Executives at US gas and electric companies off-loaded four times as much of their companies' stock over the past three months as in previous quarters, suggesting that talk of an industry recovery may be a little premature. Between March and May, the insiders sold some $128 million in stock compared to $33.1 million between December and February."

MR. CUSHMAN: Those options were in the money, and we had to do what we had to do. [Laughter] ◎

Using RECs To Finance Projects

by Samuel R. Kwon in Washington, and Roy S. Belden and Tamara Stevenson in New York

Renewable energy credits, or RECs, are becoming an additional source of financing for windpower, biomass and other renewable energy projects. However, a proceeding before the Federal Energy Regulatory Commission could award such credits to the utilities that buy the output rather than the generators that own the projects.

RECs and RPS

RECs are credits at the state level for using renewable fuels, like wind, biomass or sunlight, to generate electricity. To date, 13 states have adopted some form of "renewable portfolio standard," or law requiring utilities in the state to ensure that a certain percentage of their electricity comes from renewable sources. Five other states have adopted voluntary goals to increase the use of renewable fuels. At least another five states are considering adopting RPS-type legislation. (See the table of RPS states below). Once a state adopts an RPS, then utilities in the state that do not meet the requirements of the RPS are assessed penalties.

Currently, there is no separate federal renewable portfolio standard (although Congress is considering whether to adopt one as part of the energy bill), and RPS requirements in the 13 states vary from state to state. For instance, Arizona's RPS applies to all utilities and rural electric cooperatives. The Connecticut RPS applies to utilities, but a utility does not count as part of its electricity output electricity that it purchases from wholesale suppliers under a "standard offer."

The percentages of electricity that must come from renewable sources also vary from state to state and over time. For example, Arizona requires utilities only to generate 1% of electricity from renewable fuels by 2005 and 1.1% by 2007. Texas requires that there be statewide at least 1,280 megawatts from renewable fuels by 2003, 1,730 megawatts by 2005, 2,280 megawatts by 2007 and 2,880 megawatts by 2009.

What qualifies as a renewable fuel also varies from state to state. In all states, wind and biomass qualify. Most states also accept some form of solar energy. However, only some states allow landfill gas, fuel cells, waste, geothermal energy, wave, hydroelectric and tidal energy.

Issues With RECs

A utility can meet its obligation under a state RPS by generating the electricity itself or by purchasing power from a third party. Alternatively, the utility can simply buy renewable energy credits from a third party.

A utility hoping to satisfy its RPS obligations using purchased RECs faces at least three issues. The first issue is whether the state's RPS allows the utility to use RECs in the first place to satisfy its RPS obligations by permitting renewable generators to transfer RECs. Not all states with RPS or

RPS States

State	Eligible fuels										
	Wind	Biomass	Solar	Hydro	Landfill gas	Geo-thermal	Fuel cells	Tidal or Wave	Waste	Ocean thermal	Other
Arizona	•	•	•		•						
California	•	•	•	•	•	•			•		•
Connecticut	•	•	•	•	•		•				
Iowa	•	•	•	•					•		
Maine	•	•	•	•			•	•	•		
Massachusetts	•	•	•		•		•	•		•	
Minnesota	•	•									
Nevada	•	•	•	•		•					
New Jersey	•	•	•	•	•	•	•	•			
New Mexico	•	•	•	•	•	•	•				
Pennsylvania	•	•	•		•	•					
Texas	•	•	•	•	•	•		•			
Wisconsin	•	•	•	•		•	•	•			

Notes

1. Six more states – Maryland, New Hampshire, New York, Utah, Vermont and Washington – are debating whether to adopt their own renewable portfolio standards.
2. Municipal utilities in some states have their own renewable energy goals. For example, Fort Collins, Colorado recently set a goal of supplying 15% of its power from renewable sources by 2017. The Jacksonville Electric Authority in Florida has a goal of supplying 7.5% of its electricity from "clean" sources by 2015.

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similar programs allow the transfer of RECs for such purposes. For example, Connecticut, Massachusetts, Nevada, Texas and Wisconsin currently allow renewable generators to sell their RECs as long as the transaction is reported to the entity administering the RPS. New Jersey and Iowa do not.

The second issue is whether a utility in one state can use RECs from another state. For example, utilities in Connecticut, Maine and Massachusetts — the three states in the New England Power Pool, or NEPOOL, that have renewable portfolio standards — can use RECs from other states in the power pool (or adjacent power pools whose power flows into NEPOOL). Wisconsin does not allow out-of-state RECs to be used by in-state utilities to satisfy its renewable portfolio standard.

The third issue in using RECs is to make sure RECs are used before they expire. For instance, in Texas, RECs not used for compliance within three years will be "retired" for compliance purposes, and cannot be used by the utility that held them.

Trading in RECs

In some states, RECs are trading in auction-like markets. There are two established markets for secondary trading. One is in Texas. The Texas RPS obligates all retail suppliers of electricity to hold RECs based on the level of their annual retail electric sales in the state. The Electric Reliability Council of Texas, or ERCOT, measures the amount of the retail sales of the suppliers. ERCOT also administers the trading program, allocating RECs to generators that use renewable fuels. The utilities must obtain enough RECs either by generating the electricity themselves or by purchasing RECs on the open market.

RECs in Texas are easily transferred through a web-based platform managed by ERCOT; negotiation of the price and other sales terms is done privately. REC prices in 2002 fluctuated widely from $4.25 per mWh to $16.75 per mWh of power. In 2003, the average bid price for RECs was $11 per mWh, and the average ask price was $12.25 per mWh.

The other established market for trading RECs is NEPOOL. Of the six NEPOOL participants, three states have adopted a form of RPS — Connecticut, Maine, and Massachusetts — while three states have not — New Hampshire, Rhode Island and Vermont. The versions of RPS adopted by Connecticut, Maine and Massachusetts all allow utilities in each state to satisfy their RPS obligations by procuring RECs from generators within the NEPOOL territory, including from generators in the states that have not adopted an RPS. They also allow the use of RECs from generators in any adjacent power pool as long as the power from

REC Markets

Market	Out-of-state RECs count?	REC transferable?	Recent prices (in mWh)
NEPOOL	Yes- if from generators in NEPOOL states (CN, MA, ME, RI, VT or NH) or from adjacent power pools	Yes – via NEPOOL GIS administrator in a sale directly to third parties in good faith, on an an arm's length basis, for reasonable value	CT (Q1 '03) – bid $30/ask $45 MA(Q2 '03) – bid $29/ask $35 MA(Q3 '03) – bid $30/ask$35
Nevada	No	Yes – by joint request by seller and buyer for an approval to the state RPS administrator	
New Jersey	No	Yes – by bilateral agreement	
New Mexico	No	Yes – by bilateral agreement	
Texas	Yes – if (i) the first metering point for the generation is in Texas, (ii) the generation is for use in Texas, (iii) all generation metered at the point of injection into the Texas grid comes from the generator and (iv) approved by the Public Utility Commission of Texas	Yes – via a web-based platform administered by ERCOT with terms negotiated in private	2002 – bid $11/ask $12 2003 – bid $11/ask $12.25
Wisconsin	No	Yes – by bilateral agreement	

that power pool flows into NEPOOL.

The trading of RECs is handled by NEPOOL's generation information system, a market-priced bid-based power exchange system similar to the one maintained by ERCOT in Texas. The REC trading prices in NEPOOL vary. For instance, the average ask price for RECs from Massachusetts-based generators in the second quarter of 2003 was $35 per mWh while the bid price was $29. The ask price by Connecticut-based generators for the first quarter of 2003 was $45 per mWh, and the bid price was $30 per mWh. The NEPOOL states with RPS standards have idiosyncratic rules on what qualifies as an acceptable REC. For example, Massachusetts requires RECs to be from "new" facilities that began producing electricity after December 31, 1997.

An alternative to obtaining RECs from a trading market is to arrange for their purchase from an independent generator directly. Private sales take place among utilities and holders of RECs in states that allow transfers of RECs, but do not yet have active exchanges for trading. Such states include Nevada, Wisconsin and New Mexico. New Jersey is considering whether explicitly to allow trading. Utilities that offer "green power" to end users of electricity at a premium also purchase RECs through private transactions at times even though the states in which they operate do not impose any RPS obligations on them. An example might be a utility in Rhode Island that buys RECs through NEPOOL. However, the participation rates in half of these "green power" programs offered by some 1,240 electric utilities nationwide have been less than 1%.

Ownership of RECs

The question whether a power sales contract conveys to the buyer of electricity not only the energy and capacity but also the corresponding RECs has arisen recently in two state-level proceedings and a proceeding before the Federal Energy Regulatory Commission. All three proceedings involve qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act, or PURPA, that entered into long-term power sales contracts with utilities for the sale of their output. The contracts were signed before there was such a thing as a REC.

In one state proceeding, the Maine Public Utilities Commission concluded in September 2002 that the utilities — rather than the QFs — have the rights to RECs being traded on NEPOOL under the PURPA contracts because the utilities' purchases of QF power include purchases of associated RECs. The decision is being appealed. In another state proceeding, the Connecticut Department of Public Utility Control is examining whether the Connecticut Light & Power Company is entitled to the RECs that a QF receives from NEPOOL because RECs are an inseparable part of the entire electric output that the QF is required to deliver to the utility.

In a separate proceeding before FERC, four unrelated owners of QFs have petitioned the agency for a declaratory order that PURPA contracts do not convey RECs to the purchasing utility. These QF owners argue that the "avoided cost" that utilities pay to QFs under PURPA contracts compensates QFs only for the energy and capacity produced by the QFs and not for any environmental attributes associated with the QFs, including the RECs. FERC is currently considering the matter.

Related Environmental Credits

Apart from RECs, the volume of trading of other "environmental credits" both in the US and abroad is gradually increasing. The US has long recognized emission credit trading programs as a mechanism for achieving emission reductions in sulfur dioxide and nitrogen oxides. These programs are largely driven by mandated emission-reduction requirements.

Greenhouse gas credits are another environmental credit mechanism that is also in its infancy. The market for greenhouse gas credits is expected to grow stronger when the Kyoto protocol is implemented in the European Union countries, Canada and Japan. The protocol will take effect once one more large country ratifies it. Russia is expected to do so later this year or early next year.

The Kyoto protocol is a commitment by the international community of nations that has ratified the treaty to reduce greenhouse gases over time. Once it takes effect, the signatory countries become obligated to reduce their emissions. Greenhouse gases are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride, all measured in "CO_2 equivalents." The Kyoto protocol leaves it up to each country to reduce its greenhouse gas emissions without specifying how. The member countries of the European Union are spearheading the implementation effort.

The European Union directive on greenhouse gases is expected to establish a "cap-and-trade / continued page 32

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system." Under this system, the government in each member country would give out at least 95% of credits to emit greenhouse gases to companies in its country as it sees fit. The remaining credits are likely to be auctioned off. The United Kingdom has its own emissions trading scheme, and it may opt out of the EU program at least during the pilot phase of the EU program from 2005 to 2007. Point Carbon, a Norwegian-based research group, estimates that the EU emissions market could grow from $1.15 billion in 2005 to $8.51 billion in 2007.

The US government has rejected participation in the Kyoto protocol. As a result, an active market for trading of greenhouse gas credits in the US does not exist currently. However, trading on the Chicago Climate Exchange, an electronic exchange for trading various greenhouse gas credits among companies that voluntarily choose to reduce their greenhouse gas emissions, is scheduled to begin on October 1, 2003. Some experts are skeptical whether there will be much trading without a legal requirement for US companies to reduce emissions. To date, 14 companies and the city of Chicago have signed up to participate.

Movement to Disallow Dual Benefits

A generator using renewables to produce electricity in a state with an RPS accumulates RECs for its own use or sale to third parties. If the use of the renewables also happens to reduce greenhouse gases — for example, the generator operates a power plant using landfill gas as the renewable fuel — the generator may be able to "sell" the reduction in greenhouse gases to third parties. While there are currently no mandatory emission reduction requirements for greenhouse gases, some industrial companies purchase greenhouse gas credits to boost their reputations as environmentally-friendly companies while others might purchase the credits in anticipation of future regulations that will require reductions in greenhouse gases. A generator could theoretically end up selling the same environmental benefits twice — once in the form of RECs and once as a greenhouse gas credit.

Currently, the various forms of state RPS generally lack explicit statutory or regulatory mechanisms to curb the double counting of benefits from a single use of renewables. There are several third-party organizations that certify RECs. Most of these organizations, such as Green-e, have policies in place to prevent certification of the environmental attributes of using renewable fuel as an REC if, at the same time, the generator has also received other emission reduction credits for the same attributes or the generator is required by law to use the fuel to comply with emission reduction requirements.

Financing Possibilities

To what extent RECs and other environmental credits will become steady sources of financing for renewable energy projects depends in part on how rapidly the volume of trading in the credits increases in the future. Evolution Markets, a consulting firm specializing in environmental credits, reported that it has been involved in 50 REC trades to date in 2003. Because the REC trading market is still immature, it has been difficult to establish forward price curves that are important for developers of power projects wishing to obtain financing using RECs. There are about a dozen companies currently active in the market for RECs, according to recent published reports.

RECs and other environmental credits will probably never be valuable enough to finance the entire cost of a renewable energy project. However, as the markets in these credits deepen and prices stabilize, they should become a source of additional funds. A company may issue different tranches of debt, one of which is backed by RECs or other environmental credits. Alternatively, debt service reserves may be funded by cash expected from sales of such credits, or even insurance premiums or hedging costs may be funded in part by such credits.

Possible Federal RPS

The Senate passed an energy bill at the end of July that would impose a national renewable portfolio standard. Beginning in 2005, each retail electric supplier would have to obtain at least 1% of its electricity from renewable sources. The percentage would increase to 10% by 2020. Generators using renewable fuels would be awarded credits by the US government. A utility would have to turn in credits at the end of each year equivalent to the required percentage — for example, 1% — of its retail "base" load. It could obtain the credits either by generating renewable electricity itself or by purchasing credits from independent generators.

The House version of the energy bill does not include a renewable portfolio standard. The House passed its version last April.

The measure goes next to a House-Senate "conference committee" where senior members from both houses will to try to write a common bill to send to the president. The renewable portfolio standard is only one of many differences with which the conferees will have to grapple. They gave up on the energy bill last year after being unable to reach agreement. ◎

Renewables To The Fore?

The following are excerpts from a discussion that took place in San Diego in June. The question was, "Are renewables finally poised to take off, or is the huge interest in them — as evidenced by attendance at conferences this year — merely a sign that there is little other greenfield activity in the market?"

The speakers are Michael Polsky, president of Invenergy, an independent power company in Chicago, Merrick Kerr, chief financial officer of PPM Energy, a US subsidiary of ScottishPower, Jayshree Desai, director of finance for Zilkha Renewable Energy in Houston, Jerome Peters, senior vice president and managing director of United Capital, a prominent lender to the renewable energy sector, and Christopher Moakley, president of Meridian Energy, which is in the business of raising capital for energy projects that receive tax subsidies. The moderator is Keith Martin, a Chadbourne lawyer and editor of the NewsWire.

MR. MARTIN: Michael Polsky, you were probably more prescient than most people in the merchant power industry. You had a power company called Skygen that you sold at the top of the market. Now you have started a new company — Invenergy — to focus on windpower projects. Do you know something that the rest of the market has missed?

MR. POLSKY: I don't know. I can tell you why we are looking at wind.

After I set up the new company, we looked at various options, including trying to buy distressed assets, which was the subject of the earlier panel. I don't see a lot of asset sales because people have nothing to sell. With the collapse in prices, many equity owners no longer own any equity in assets. So the reason we don't see any merchant sales is not because people don't want to sell, it is because they have nothing to sell.

So we came to look at wind. I think we will hear today that there are a lot of challenges in wind. When I started Skygen in 1991, most merchant power companies were heading overseas because they thought that was the place with the greatest opportunities. We stayed focused on the US. We always seem to be slightly out of step with the rest of the market. Here we go again. We like aspects of wind generation because the projects usually have long-term contracts and, in that sense, are similar to the earlier generation of independent power projects in which we have expertise. In addition, you have the fact that many people see wind as a positive thing environmentally. There is a push by governments around the world to do renewable energy. Whether these factors make for a good future in wind, I don't know.

MR. MARTIN: Merrick Kerr, Scottish Power has set a goal of building 1,000 megawatts of wind capacity in the US through its subsidiary, PPM Energy. Why has the company devoted so many resources to wind?

MR. KERR: When we decided to build unregulated business in the US, we looked for the best point of entry into the US market. It was in 2000. Most of the greenfield activity was in gas generation, but was that the future? The fundamentals pointed to wind as the place for us. There was no dominant player in the US market. We had experience with wind back home in Scotland. There was also the fact that our sister company, PacifiCorp, which is a regulated utility, has a tax base to use the production tax credits that the US government offers as an inducement to generate electricity from wind. That may give us a little bit of an advantage over other wind developers.

Enforced Demand

MR. MARTIN: One of you argued on a conference call we held last week to prepare for this panel — I believe it was Michael Polsky — that the only way the wind business works is if the government orders utilities to buy the output. Jayshree Desai, do you agree?

MS. DESAI: I agree that something has to stimulate demand, and RPS will allow us to compete more effectively with some of the other alternatives.

MR. MARTIN: And "RPS" is —

MS. DESAI: A renewable portfolio / continued page 34

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standard. Certain states have adopted laws requiring that a certain percentage of the electricity that utilities supply to their customers must come from renewable fuels. For example, Texas has one, and it has accounted for the huge growth in the wind industry in that state. I do think that in order to compete effectively and have the good guys win, you have somehow to stimulate demand. I do not see that happening without an RPS.

MR. MARTIN: How many states have renewable portfolio standards now?

MS. DESAI: I want to say 13.

MR. MARTIN: The European Union also has a law setting a goal for utilities to generate a certain percentage of electricity from renewable sources. Does anyone know the percentage? I believe it is moving toward 20%.

MR. KERR: It depends on the country. For example, in the UK, it is 10% by 2010 and 20% by 2020.

MR. MARTIN: California just adopted a stiff RPS. Does anyone know the percentage.

MS. DESAI: I believe it is 20% by 2017.

MR. MARTIN: And what is the percentage of renewable energy generated currently in California?

MR. POLSKY: About 11%, not counting hydroelectric power.

MR. MARTIN: Are there other factors that are contributing to the growing interest in wind besides RPS?

MS. DESAI: Spiraling natural gas prices make electricity generated from wind better able to compete with electricity from power plants that run on gas. The war in Iraq has also given a boost to wind developers. It reminds people of the need to do things that reduce our dependence on imported oil and gas. So there are other things that are helping push the interest in wind, but, not to sound like a broken record, there must be something more in order to turn windpower companies into more than just developers of one-off projects. To have a real business, there must be a renewable portfolio standard.

MR. MARTIN: There are 37 states without RPS. Without RPS, what do you have?

MR. POLSKY: Not much more wind development than you have right now.

We see the same thing happening with wind that we saw with gas in late 1990s. Everyone is rushing to grab potential sites in anticipation that something will happen and they can flip sites to someone else who will develop or complete development. You see tremendous activity going on in the wind market as far as acquiring sites. But I think that is where it stops until buyers can be found for the electricity, and they are hard to find.

MR. MARTIN: If utilities are required by law to buy in 13 states, is it still hard in those states to find a buyer?

MR. POLSKY: First of all, I don't know what percentage of electricity those 13 states represent. For example, it was very soon — within a few years — after Texas introduced its RPS that the percentage requirement for renewable electricity was met. Minnesota has been fairly active in this area, but the threshold percentages phase in over time. Most take until 2010 or 2015 to ramp up.

I personally feel that electricity from wind is less expensive than from gas today. But the only people who can buy are the aggregators because of the intermittent nature of output from wind farms. We don't have 100% capacity factors. Therefore, you cannot go sell wind on the retail market or to industrial users or to anybody who needs a level supply of electricity. There are a few exceptions like universities or some other entities that buy wind indirectly, but — in general — the only potential buyers are aggregators, and aggregators like utilities don't want to bother with it. So no matter how inexpensive wind is in relation to the alternatives, you need an RPS in order to stimulate demand.

MR. MARTIN: Is there a role for the Morgan Stanleys and other electricity traders of the world to act as aggregators?

MR. POLSKY: I don't think these guys will aggregate because they are in the business of making money.

MR. KERR: What the customer wants to buy is a shaped product, and that is what wind companies will have to offer to thrive. PPM has done that for some customers with help from intermediaries. But the cost advantage that wind has right now against gas quickly disintegrates because of the prevailing transmission tariffs for wind electricity. If you can find a Bonneville Power Administration or another entity that like to handle transmission for you, then the cost is a couple of bucks and no more. But if you have to do it yourself, you are quickly talking about —

MR. MARTIN: The reason that transmission is expensive is the intermittent nature of wind output means that wind farms must reserve more capacity on the grid than they are likely to use? Or is it that wind farms are built in windy areas where people tend not to live so that the electricity must travel a long distance to reach consumers?

MR. KERR: Both.

MR. MARTIN: Jayshree Desai, what has Zilkha's experience been in competing on cost against electricity from gas-fired power plants?

MS. DESAI: You have to look on a state-by-state basis. In some states, we are able to compete very effectively. In other states, the price of gas is so low that we have no chance of winning a power purchase agreement solely on the basis of cost. Even in states where we enjoy a cost advantage, we still meet resistance from some utilities that just do not understand our product and resist dealing with a potentially intermittent supplier. Wind developers face the additional hurdle of having to educate utilities about the benefits of drawing electricity from a diversified portfolio. Notwithstanding this, at the end of the day, wind developers must be able to compete on price. If your price is not competitive, you are not going to win the contract.

MR. MARTIN: Jerry Peters, you are making something of a specialty of lending to power projects that use renewable fuels. Why is wind attractive given what we have heard today that there is really no wind business unless utilities are required to buy the output?

Competitive Edge

MR. PETERS: First, let me say that I don't view wind as being any more attractive than any of the other renewable assets I have in my portfolio. But the key really comes down to what renewables can do that no other fossil fuel generation asset can do: renewables can produce at a fixed price. They can offer to the marketplace that is willing to buy their electricity a fixed price over a long term. Not many gas-fired plants being built or that were built in the last 10 years can make the same offer. Another thing that wind has going for it is technological improvements in wind turbines over the last 10 years have led to a dramatic reduction in capital cost per megawatt of installed capacity. The capital cost is now approaching a level at which wind farms can compete with four or five dollar gas. And wind is not alone in this respect. Improvements in geothermal technology and in bio technologies have put other renewables projects in the position to compete effectively on price, as well.

People forget that each individual in the United States produces about seven pounds of garbage a day. Most of this garbage is organic. When you deprive it of oxygen, it produces methane. A large number of landfill gas projects have been developed in the last 10 years. These projects are in a position to sell gas for less than the cost of competing natural gas and, add on top of that, that they can agree to supply the gas at a fixed price under a long-term contract.

MS. DESAI: Keith, if I could add one thing. I agree that wind has 20-year long-term PPAs, but in one state we are facing a situation where the utility refuses to enter into a 20-year contract. This sets up a struggle between what can be financed versus what the utilities want. I don't know whether there is a way to overcome that hurdle. Will banks ever be willing to finance wind farms on the basis of shorter-term PPAs? We have the problem in certain states that we are not going to be able to sell our electricity unless we find a solution to that problem.

MR. MARTIN: Let me probe further on what the wind industry needs to succeed. Isn't the wind industry divided on the question whether it wants a national renewable portfolio standard? The fear is that if the US government orders utilities nationwide to buy or produce a certain percentage of electricity from renewable fuels, it will impose a weaker standard than the industry has been able to get from the states. Michael Polsky, do you agree?

Wind as Infrastructure

MR. POLSKY: Let me make a broader statement about renewables, wind in particular. I think people have to look at wind as a national infrastructure project, okay? Wind remains largely untapped in this country as resource. It will always be available. That is why Europe went the way it did. The Europeans are not stupid. And there is something to be said for the approach Europe adopted to encourage wind. They did not do it through tax credits, but a cost-based system where a minimum price is set for electricity from wind or renewables with the result that there is the same incentive for smaller developers without a tax base to develop wind projects as for larger companies to do so.

Wind is an infrastructure project, and the utilities are not in the business of building public infrastructure. That is a job for state or national governments. At the end of the day, the debate should not be about subsidies for this or that. It should be about creating a national renewable infrastructure. Look at what has happened with */ continued page 36*

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gas. Everybody thought gas was plentiful. And maybe it is plentiful, but $6 gas certainly is very expensive. We see what happened with nuclear power. Nuclear energy is not economically competitive today. I personally believe that wind and renewable fuels in general are like the United States highway system. If the highways had to be economically justified up front, no one would ever have built the interstate highway system. I think we as a country are ignoring a source of fuel on which we can rely not just for the term of a 3- or 5-year PPA, or for this generation, but forever, and the government will have to make a decision. If we don't make that decision, then wind farms will not be built.

MR. MARTIN: Merrick Kerr, why is it so important to the industry that General Electric has jumped into the business of manufacturing wind turbines? Why is this such a great source of excitement among wind developers?

MR. KERR: It is the promise of further improvements in technology. Let me add to what Michael Polsky said. If we are going to get the utilities to buy our electricity today, then the price must be at least close to the price for electricity generated from natural gas at the point where they buy it. I agree that to make a real business, the industry needs an RPS. If you just look at the states that have an RPS today, you are talking about 20,000 megawatts of capacity. If the RPS were extended to the entire country, that would create the potential for 60,000 megawatts.

MR. MARTIN: People who are not in the wind business may not realize that the government pays as much as 75% of the capital cost of a wind project through tax subsidies. The main subsidy is a tax credit of 1.8¢ a kilowatt hour at the federal level. The problem with this credit is it has to been renewed periodically by Congress. For example, this year is another year when it is in danger of expiring. Michael Polsky, I believe you had some interesting data about how this periodic uncertainty every so often about whether the credit will be extended hurts the wind business.

MR. POLSKY: Somebody else had it.

MR. KERR: Something like 1,700 megawatts of new wind projects were built in 2001. Last year when there was uncertainty about whether the credit would be extended, only 300 to 400 megawatts of new wind capacity was installed. This year is another year of uncertainty.

MR. MARTIN: Chris Moakley, you had a comment about the uncertainty surrounding the tax subsidy.

MR. MOAKLEY: It is difficult to get the large institutions that supply equity to affordable housing, wind and similar projects to commit to a program where the inducement is a temporary credit. Investment in affordable housing did not really take off until the tax credits for such projects were made permanent.

More Investors Needed

MR. MARTIN: Jayshree Desai, there is a perception in the market that there are too few potential equity investors in wind deals to satisfy the need for capital in this business. Is it true and, if so, why?

MS. DESAI: We agree that it is a small market. It was much easier to raise money for wind projects a couple years ago when the energy industry was booming, but now with many of the traditional energy players having fallen on hard times, we are having to try to come up with new structures that parcel out risk a little differently than in the past. The goal is to find something to attract more nontraditional players into the market — investment banks, financial institutions, large companies with tax bases — but they are willing to take only so much risk. There are some investors who are willing to take the wind and technology risk, but they also must have a tax base to be able to use the tax credits. You have to find somebody who has all three of these characteristics.

Then there are some other potential investors who are willing to take price risk but not wind risk. Some are willing to take technology risk but not price risk. It becomes a complicated puzzle to find a structure that will attract enough equity to the project. There are only maybe 10 or 12 players that I would go to today when I have a wind farm to sell.

MR. MOAKLEY: Keith, let me comment on that too. The wind companies are not going to get the pure financial players as equity investors unless the financial players feel like they can make a long-term commitment to the business. They will not devote the resources required to understand the business in order to make a one-off investment, or even to make investments for just a couple of years. They want to see permanency in the tax credit.

Let me give you a real-life example. I am a simple guy who has to relate things to everyday examples. I have a wonderful wife and three beautiful daughters, and they like nice clothes.

If they walk into a store whose name they don't know, they might say to the clerk, "You have some nice clothes here, but we worry you may not be around after this year." Maybe the store has a nice product, but they don't know if they can replicate their behavior by spending a lot of money there. Now, if you put my wife and three daughters in an Ann Taylor or a Talbots, I tell you, they are dumping tremendous amounts of money and they will replicate their behavior. [Laughter]. I think that's what the large institutional equity participants want to do as well. They want to have some confidence that the product will be around for a while.

MR. MARTIN: Jerry Peters, we have to draw this discussion to a close. Any final thoughts?

MR. PETERS: Yes, financing renewables is a very difficult job because of the complex tax structures required. We are dependent on tax credits to make wind and other renewables work. Many lenders with experience with other types of power projects will simply look for a long-term power purchase contract that ensures enough money will be generated from electricity sales to pay back the loan on schedule. It is not as simple as that for renewables projects. We have to look also at the entity that has monetized the tax credits. And in some states there are renewable energy credits that are created under the renewable portfolio standard and for which there is a market, so you may have yet another party monetizing the renewable energy credits. The lender has to make three credit decisions before advancing the loan.

MR. MARTIN: Any other points that it is important for the audience to hear?

MR. KERR: Maybe just one, and that is emissions. A 100-megawatt gas-fired power plant is equivalent to 85,000 automobiles in terms of its emissions and the equivalent of the absorption of 60,000 acres of trees. Wind projects not only tap an inexhaustible fuel, they also reduce emissions.

Merchant Transmission Projects

The following are excerpts from a discussion about potential opportunities in the project finance market. The discussion took place in San Diego in June. This segment focused on merchant transmission projects. The question posed was, "The area where there is the clearest need for more capacity is electric transmission, but transmission projects face daunting obstacles. Is it sheer fantasy to undertake such a project?"

The speakers are Robert Mitchell, president and chief operating officer of Trans-Elect New Transmission Development Company, Jon Erik Larson, a managing director of Trimaran Capital Partners in New York, Dominic Capolongo, a managing director of Credit Suisse First Boston in New York, and Adam Wenner, a regulatory lawyer with Chadbourne in Washington. Michael Polsky, president of Invenergy, asked a question. The moderator is David Schumacher, a project finance lawyer who is in Washington for part of each week but who works primarily out of the Chadbourne office in Houston.

MR. SCHUMACHER: Bob Mitchell, what were some of the things that made Trans-Elect think the time was ripe for a private company that would focus on transmission?

MR. MITCHELL: In 1998, when I started thinking about transmission, I had the luxury of not coming from a utility background. I was looking at this more from a public policy point of view independent of transmission and the benefits that it could bring to the consumer. In analyzing the situation, it struck me in 1998 and 1999, when we were in the process of forming Trans-Elect, that the utilities had a lot of opportunities where they could place their money in non-regulated activities and get a lot bigger return than the 10 1/2% or 11% return that they were allowed for their regulated businesses.

The more I looked at it, the more clear it was that the direction of regulators is to take more and more power and control over that asset away from the utilities. So I thought that if I were a utility CEO, why would I want to continue holding on to an asset that, for most utilities, is only about seven to 10% — maybe in some cases 12% — of their total asset bases. Here was an opportunity to monetize that asset. From research that I was doing, it looked to me like we were going to be able to pay a premium.

It was really on that basis that we — some colleagues of mine who knew more about utilities than I did — came together, and we formed Trans-Elect. We did some pioneering. We were able to be part of the consortium that put together the first transaction where an independent company bought a transmission system from a utility in Canada. We bought it from Trans-Alta. Then we were successful in putting together an acquisition from Consumers Energy in Michigan. More / continued page 38

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recently, we succeeded in putting together a project in California, which is actually new transmission, called Path 15.

Frankly, after having spent four years or so working with utilities, I think I clearly underestimated the bond that utilities have with their transmission systems. It's like jerking an arm right out of the body in order to get a utility to part with one.

There has been some progress. KKR and Trimaran were successful in buying the Detroit system. Over the next few years, you are going actually to see a lot of activity on the transmission side.

MR. SCHUMACHER: Jon Larson, why are transmission projects attractive to an investment fund like Trimaran?

MR. LARSON: First, this is a very large asset opportunity. Every other commodity has an exchange or some sort of agency that facilitates trades. Stocks are traded on the New York Stock Exchange. Commodities are traded on the Chicago Board of Trade. Effectively I think what is required in order to make commodity markets work for electricity is some large entity steps in that has the infrastructure to facilitate trades.

Right now, we are looking at a world that looks like 90 different Spokane Stock Exchanges. We are trying to consolidate those 90 into something that looks like a New York Stock Exchange, an American Stock Exchange or the NASDAQ. Funds such as KKR and Trimaran have access to the larger pools of capital that are trying to seek more predictable returns than are available in the merchant power market. In order to satisfy that investment criterion, we may be targeting lower rates but a much more stable rate.

US government policy has been to encourage entities that do not have a natural monopoly in the power supply market to invest in transmission. We consciously decided when we started this buyout business — now six years ago in Trimaran — that we were not going to purchase power plants. We will not pursue power plants basically because we figured we were not as smart as most of the other people in this room.

Best Investments

MR. SCHUMACHER: Is it safe to say that as of right now, the best way to invest in transmission is by acquiring existing systems, or is there a realistic possibility that some greenfield transmission projects will be built and earn an attractive return?

The best opportunities are in constructing new transmission lines rather than buying existing assets.

MR. LARSON: The best opportunities right at this moment are, in fact, new construction. It appears that the US Senate is preparing to clip the wings of the Federal Energy Regulatory Commission in the energy bill. If it does, then I think that sales of existing systems by the integrated utilities will slow. Therefore, the Trans-Elects and Trimarans will probably find greener pastures in fixing transmission problems that are not being addressed by the integrated utilities.

MR. MITCHELL: Let me add to that. The most recent study on the subject of what needs to be done to the transmission infrastructure was done by the Edison Electric Institute about a year and a half ago. EEI concluded that over the next 10 years, there will be a need for $56 billion of investment in transmission. It did a survey of the utilities to find out what investments are planned, and the number came to $24 billion. Since then, 60% of the utilities in this country have been downgraded, and some are in bankruptcy or near bankruptcy. I think it is fair to predict that that $24 billion shrank rather dramatically.

I do not want to create a lot of competition. However, there is a tremendous backlog of transmission needs in this country. There has been underinvestment and almost disinvestment in transmission over the last 15 to 20 years.

The issue comes down to whether the United States is prepared to institute enough regulatory certainty to enable companies like ours to take the risk of developing new transmission. When you are a utility and you decide you want to do a new transmission project, you have basically unlimited resources to do the planning, the permitting, the regulatory process, and if the project must be abandoned, you will get that money back through rates. For independent companies, it is all risk. You have to do it a lot smarter and spend your money more slowly, but the need is there.

MR. CAPOLONGO: I have to agree. As you said, in 1990's, utilities had a lot of other things to put their money into, and transmission was really a non-core activity, the investors did not care about it, and it produced a low return. It carried a low risk for a utility, but there was a low return. Everybody was thinking about the 20% return that could be earned on the unregulated side of the business. Now many utilities have been burned in their unregulated businesses, and they have, in my view, unrealistic notions about the value of their transmission assets partly due to what has happened in some of the recent purchases and partly from the hopes that FERC premiums will come that have not yet happened.

As a long-term value proposition, clearly the best place for an investor to put his money is in new transmission. Having said that, such projects require more equity, less debt, and long-term view. You cannot look at a three-year time horizon to get your money back. It takes three years to build the darned thing, much less to get your money out of it. However, on a dollar-for-dollar basis, if you want to put a dollar to work in a place that will earn the highest return, it is best to put it into a new build rather than pay 1.6 times earnings for an existing property.

Key to Financing

MR. SCHUMACHER: As a lender, what do you need to see to lend either to a new build or to someone who wants to acquire an existing transmission system?

MR. CAPOLONGO: That is an interesting question. The debt markets are completely unpredictable. Bank debt — if you are doing new build or anything on a discrete basis using project financing — can be very high priced. The market is significantly restricted, as Jon Larson can attest given his recent pain and suffering. If you use the double leverage structure that many people are using, you will have to contend — at least at the upper level — with cash sweeps and all those other things that limit your ability to recycle the cash generated by the asset and to put it back to work. You can build or buy into a sweep situation, but that is all you will be able to do with the money you raise.

The Holy Grail that new transmission companies are after is they want to build enough of a foundation to be able to borrow traditional corporate debt. That frees up the cash that is generated from existing assets to reinvest in new projects.

A year or even six months ago, the popular wisdom was that one could not borrow in the capital markets for a pure transmission company. However, lately rates in both the bank market and the capital markets have been extraordinarily low. Prices are coming down, people seem to want to put their money to work and are lending in situations where I would not have thought even six months ago that a financing was possible. Therefore, given the right size financing, you can now do a corporate financing and take the cash to put into projects.

MR. SCHUMACHER: If I'm not mistaken, it seems that these projects are not financed based on long-term contracts, but rather are financed as if the transmission company was a standalone utility with a rate-based asset. Is that correct?

MR. CAPOLONGO: The current view of the regulatory environment is that you don't need the contracts at least as to the portion covering the debt financing. The assets are usually essential to the utility system. This makes people more comfortable relying on the revenue stream.

Regulatory Distinctions

MR. SCHUMACHER: Let me step back. I probably should have started with Adam Wenner. I know that the Federal Energy Regulatory Commission distinguishes between merchant transmission projects and independent transmission projects? What is difference?

MR. WENNER: Most merchant projects are small, newly-constructed links that interconnect two existing transmission systems that otherwise have natural barriers between them and, therefore, have different system costs. An example of such a project is a line connecting — let's say — Connecticut to Long Island. Several merchant projects that fit this description have been proposed. Most are short and run under the sea or a river or sound. They connect two utility systems that are not already

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connected due to natural barriers.

The other type of project is basically acquisition of an existing transmission grid from an integrated utility. For the most part, those are the types of transactions that Trans-Elect and Trimaran have done. The Path 15 project in California is an exception. It is a new build. FERC still views the transmission system as a regulated monopoly, even though someone has now acquired it from the utility, and it remains subject to regulated pricing.

Finally, there is a third type of project at which FERC has looked, but I don't think anyone has done. It is an alternating current system, which is a participant-funded and participant-owned addition to an existing system. Most existing transmission lines are direct current. Direct current is more controllable in terms of how electricity flows. Let me ask the others whether they see much future for alternating current projects?

MR. LARSON: Let me tell you the issue with alternating current systems. Let's imagine that you decided to take one particular section of the New York Stock Exchange over to Lehman Brothers and Morgan Stanley. They pay the cost. It facilitates their trading of certain stocks. How are you going to parse the revenue? Right now we have an extremely complicated way of billing. I mean, we haven't even finished figuring out how we are going to create a market and already we have to parse it into little pieces? As anyone in the telecom industry can attest, most of the continuing war in that industry is how you do the separations with respect to long-line carriage. That's where we are in transmission. Do you really want us to go through that war for the next 20 years?

I can see why people are talking about alternating current, but frankly, I think it is completely unnecessary with the likes of companies like Trans-Elect and our international transmission company. And I will tell you why. The way we make money is by investing money. We don't have generating facilities to protect. We don't want to keep all of you wholesale generators off our system. We want to invest in an intertie. We want to accommodate you and enable you to move your power into the markets where you want to deliver it.

What is required is that, as it goes through the regional bidding process, there must be an imprimatur of prudency on that investment for us. As soon as that imprimatur is there, we will make the investment. We are not going to go through this long conversation with you about how much you will have to reimburse us for the cost of the intertie up to the substation and then beyond the substation, and you are going to have to do this and you are going to have to change that. All that is moot. We will make investment. We will be spending our own dollars and not yours.

PUHCA repeal will open the door to new players, but it is not clear how many will commit the considerable time required to learn the transmission business.

PUHCA Repeal

MR. SCHUMACHER: Adam Wenner mentioned in a regulatory update just before this session that Congress is looking for the Nth time at repealing the Public Utility Holding Company Act. If that were to happen, what impact would it have on independent transmission?

MR. MITCHELL: Jon and I were actually talking about that earlier. It would remove some constraints on utility mergers.

FERC has an interesting aspect to this that actually Jon pointed out, and that is FERC wants to make a distinction between generators and companies that just do transmission. In our two cases, we do not have generators involved. And so a utility that owns generation and would like to expand and compete with us will be constrained from doing that because it does not pass the independence test for ownership of transmission.

MR. LARSON: I think, Bob, you might want to add that we both would love to see the Public Utility Holding Company Act repealed because in order for our companies to make sense, we have to be able to operate in multiple states. There will have to be holding companies when we begin doing what we want to do.

MR. WENNER: Repeal would also open the door for others to enter the business who are neither integrated utilities nor transmission holding companies — say a Microsoft or a PacBell or Mitsubishi.

MR. LARSON: But Bob and I will tell you that it has taken each of us three to four years to understand the fundamentals of this business. I think there will be others who emerge, but I don't think the competition will come from the major utilities because I don't think FERC will permit it. And then the question is among the others, who is going will commit the dollars and time required. The intellectual capital required to operate in this space is scarce. It won't always be scarce, but it is scarce today. It will take a major upfront investment for a new entrant to learn the business. There have been other investment funds that competed with us to acquire existing systems, and they were not even close to our bids. The reason is they don't really understand the business.

MR. MITCHELL: I think you could ask Andrew Schroeder [of Energy Investors Funds] to talk about what they had to go through to bone up and get comfortable with an investment in Path 15. It's ugly enough that now that I've suggested it, I'm not sure actually that I want to talk about it.

MR. SCHUMACHER: So there is no real fear about the utilities taking over the space?

MR. LARSON: If they own power plants, then at least as long as someone like Pat Wood or James Hecker is running the Federal Energy Regulatory Commission, they might be allowed to buy, but they will not be allowed the premium returns. They will not get the regulatory treatment required for such returns, and they will certainly get a lot of scrutiny with respect to their interconnection policies.

Hurdles

MR. SCHUMACHER: Bob Mitchell, Trans-Elect is involved in Path 15 here in California. Tell us the two or three biggest hurdles that you had to cross to make that project a reality.

MR. MITCHELL: When we started Trans-Elect, we made a decision that we would not get involved in new transmission because there was no regulatory incentive. In fact, there was a disincentive. But when I saw the announcement by the US Department of Energy that the energy secretary, Spencer Abraham, had decided to invite the private sector to become involved in the expansion of Path 15, which had been talked about for 12 or 15 years and was undoubtedly the most notorious transmission congestion point in the United States, I thought what the hell. It took me a couple hours to bang out a response. Then we waited to see what would happen.

What happened is 14 parties also banged out responses, and the good news was that we were selected. The bad news was that the energy department selected 13 of us to participate. So on a $300 million deal, we had I think 6.75% or $20 million which was way below our threshold. But I looked at the list of others and said I don't think most of them are going to stick around. It turns out that none of them did. Only Pacific Gas & Electric, the Western Area Power Administration itself and Trans-Elect ended up remaining involved. So we are financing 100% of the line. PG&E is financing the substations at each end of the new line.

We have had many challenges. One was to work out a structure for a public/private partnership that never had really been done before where you have an existing utility that, by the way, is in bankruptcy, and an independent transmission company working with a federal agency. That was a major challenge. I think we've created a pretty exciting model that probably could be replicated. We hope that it will.

Another challenge was that FERC had never given the sort of declaratory order before that we felt we would need to proceed with the investment. We went to FERC and said this is what we plan on doing and we want you to declare in advance what the economic conditions will be. FERC to its credit gave us a declaratory order allowing us a 13 1/2% return on our equity. It also granted us a three-year moratorium on rate adjustments so that we could assure the people supplying us capital that things would be steady for three years. Significantly, FERC also gave us the ability to do a hypothetical capital structure, which meant that our rate was going to be based on the assumption that the capital structure was 50% equity and 50% debt when, in fact, we were going to be able to finance the project with roughly an 80-20 capital structure. Those three things were absolutely crucial. Without them, we would not have been able to get our investors to take the risk and invest money.

The next hurdle was the environ- / continued page 42

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ment in California. The California situation is often described as being as bad as, or worse than, a third-world country. This reputation was not without justification. However, for those of you looking at investing in California, I want to emphasize that there is new leadership at the California Public Utilities Commission. The new people in charge have worked a miracle at turning around the adversarial attitude, at least in the case a Path 15. Maybe if San Diego Gas & Electric were here, it might have a slightly different view, but we had our major test two or three weeks ago where the commission had to vote whether to continue with what the previous chair of the commission had started — mainly suing FERC over our rate case. The commission decided to drop it. It removed itself from the lawsuit as the suit relates to us. It essentially said it is now supporting the project going forward. That was a very positive move. It sends a signal to the market about investing in California. Everyone here ought to take a look at it.

MR. SCHUMACHER: Was political risk insurance available in California?

MR. MITCHELL: Well, I told you in the beginning that I had the luxury of not having a utility background. I do have a political background, and it gives me a degree of comfort working in that environment that perhaps somebody who does not have the same background would shy away from — and I would strongly advise them to do it. [Laughter.]

Regulatory Policy

MR. SCHUMACHER: You talked earlier about FERC's rate of return policy. Has the FERC policy had the effect of encouraging investment in transmission assets? Has FERC done enough to encourage such investment? If not, what does it still need to do?

MR. LARSON: Well, I think we're all through right now. The fact is the premium returns are icing on the cake. Both Bob Mitchell and I were pursuing transmission projects going back four or five years without necessarily presuming that there would be favorable rates of return. But it helped that there was a trend by the regulators toward removing control over an asset class from integrators, turning ownership of transmission for them into merely a passive investment with a low return. In PG&E's case, it looked like it might involve a return on equity in the sevens in a market where debt rates were in the sevens. This makes transmission uninteresting for the utilities as an asset class.

It would be hard to borrow to finance a merchant transmission project, but most projects are not truly merchant. They are regulated businesses with rate bases.

The premiums were not put in there for our benefit. They were put in there in order to enable us to offer prices that were at least in the range of what sellers were expecting. Frankly at a 10% return on equity without some of the regulatory treatment that we have received — the ability to book an intangible asset — we could not have paid anything close to the prices that we have paid to sellers.

MR. SCHUMACHER: Dominic Capolongo, from a lender's perspective, are the rates of return that are allowed on these projects by FERC a benefit in the eyes of the debt market? Do they make financing transmission more attractive?

MR. CAPOLONGO: No, I don't think so. As Bob Mitchell said correctly, the debt markets are looking for certainty. They are not looking at the premiums. They want a regulated rate of return that is fixed over the life of the debt. As far as I can tell, all — if not all — of the financings have had maturity dates tied to the period over which the rates have been fixed. You have not seen lenders willing to go out much longer than that. What the lenders want is cash flow certainty.

MR. SCHUMACHER: How is the lending market dealing with the regulatory uncertainty? Regulatory uncertainty infects the entire power industry.

MR. CAPOLONGO: The regulatory uncertainty to which you are referring affects equity participation more than debt participation. As these guys have said, the premiums suddenly opened a big door. The result is you have a lot of people chasing these deals but not understanding the FERC situation, and not having the background to analyze the state issues with which transmission companies have to deal. I think you will see many of those players who came running in the door go running out the same door. You will see fewer people truly interested in transmission in the long haul. Regulatory uncertainty affects the number of equity investors.

On the debt side, I don't see any big change. The ability to do long-term financing rather than short-term will be enhanced by the more regulatory certainty there is. But financing for these projects will remain available.

Financing Merchant Risks

MR. POLSKY: I have a question for the panel. I do not understand how people can develop merchant transmission — here you have been talking about new construction — without long-term contracts for transmission. It seems inconceivable in today's climate that somebody can get financing for merchant transmission. I can understand how one can get financing to buy an existing transmission system where you have fixed revenue. And Path 15 is a unique case where the developers were able to fix their economics in advance probably because of the political situation in California. But I do not understand how anyone can get financing to build a new line.

MR. CAPOLONGO: You are talking about true merchant transmission. That is why I said that for purely merchant projects, you are looking at having to cover the capital cost solely out of equity. You will not find the debt markets receptive, at least not in the early stages.

MR. LARSON: I agree. However, some things that may be characterized as merchant aren't merchant at all. I mean, you are building a rate base. That is essentially what Path 15 is. It is a rate-based transaction. There is one distinction between Trans-Elect and us. We don't go for hypothetical structures. Therefore, we are financed a little less aggressively.

MR. SCHUMACHER: Why is that?

MR. LARSON: Because we are scared of what the regulators might do six years from now.

MR. MITCHELL: I would just add to this discussion that Path 15 is regulated. But there is another important distinction, and that is there is an independent system operator in California. We were able to put the capacity for Path 15 into the ISO, and we've socialized the cost of Path 15 across the entire rate base in California. If a new line is going to be built in an area where there a regional transmission organization or ISO and you have the ability to have the capacity factored into the planning process of the RTO, then it is a very different situation.

We are working to build a 480-mile line — approximately a $600 million project — called the Navajo transmission project. It will cross three states. There is no RTO in the southwest at this point. I think there will be one there eventually. We are facing all of the challenges that you articulated. We will have to have some firm contracts in order to finance it. If we don't have such contracts, then it won't be financeable.

MR. SCHUMACHER: Jon, there are certain advantages for independent generators in dealing with independent transmission providers versus dealing with public utilities. Talk further about them.

MR. LARSON: The first one is we are willing to engineer or talk to you about whatever you feel you need to interconnect, assuming we can get it through the bidding process at the RTO. We will also spend the money because the ratemaking mechanism in place for us is such that it means essentially that we will get a return on our investment.

There is another advantage we have over the incumbents. Let's be blunt about it. When they spend the money, it means a rate increase for transmission service. We need to be able to show that there is a positive benefit from the investment. In the case of the International Transmission Company, we had a perfect example. I can't promise you will find something like this in every case, but we began to comb every single engineered project on the ITC's books that had not been pursued. We had people run the numbers on each of them in order to come up with an analysis of what the net benefit was in each case. We identified one line that is basically a voltage rerating and on which we are spending $8 million to improve. The net one-year benefit to the marketplace is $60 million. Some of the $60 million will be captured by / continued page 44

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the power marketers, but ultimately much of it will find its way to the consumer.

That's an investment that would have been irresponsible for Detroit Edison to have made. It would have not served the best interest of the Detroit Edison shareholders. It is not that the incumbent utilities are dragging their feet about investing in transmission when the RTO is trying to encourage them — although we are looking at one situation where a utility is dragging its feet and the RTO wants us to get involved. It is not that the utilities are bad people. They are serving the best interests of their shareholders.

The benefit of having an independent transmission company is the way we serve our shareholders is by prudently investing in transmission and frankly investing as much as we can, subject to the prudence review which means that we need to work out all the cost alternatives.

MR. WENNER: Let me ask one question about the prudence review. One advantage of being in the transmission-only business is that both of you are subject only to FERC regulation and not to state regulation. Are you able to go to FERC —

MR. LARSON: There are 23 committees that you have to clear before you make any investment greater than $5 million. Twenty-three committees.

Iraqi Oil Cranks Up

by Kimberly Heimert, in Washington

Iraq's execution of term contracts in late July for the export of oil with 10 international oil companies signals a level of stability in Iraqi petroleum production that many in the industry doubted would occur until next year, but it is still unclear whether Iraq's oil revenues will meet the targets required in its new budget.

Iraq has entered into oil sales contracts with ExxonMobil, ChevronTexaco, ConocoPhillips, and Marathon (all US companies), BP (an English company), Royal Dutch/Shell (an Anglo-Dutch company), Vitol (a Swiss company), Total (a French company), Sinochem (a Chinese company) and Mitsubishi (a Japanese company). Although the exact terms of these contracts are not public, it is generally believed that each of the 10 companies will lift approximately 2,000,000 barrels of Basra light crude each month from August 2003 until December 2003 (which is an average of 650,000 barrels per day (bpd) for all ten of the contracts) — all at the Persian Gulf export terminal of Mina al-Bakr in southern Iraq.

After several missed production targets in Iraq since the end of major hostilities with the US, many in the petroleum industry believed that Iraq would not be able to commit to a consistent production of 650,000 bpd until at least 2004.

Future Uncertainty

Before the war with the US, Iraq's domestic oil consumption was approximately 500,000 bpd. Because of damage to various parts of the Iraqi infrastructure (particularly power plants, power grids, and refineries) caused by bombing, looting, and sabotage, domestic consumption has varied widely, but is expected to reach at least pre-war levels as the infrastructure is repaired. Therefore, Iraq must produce more than 1,000,000 bpd to meet both its domestic consumption needs and its export obligations.

It is unclear whether Iraq will be able to maintain such a production level for the next five months, as there have been conflicting forecasts of its expected production capacity through the end of the year. Initially, US and Iraqi officials announced that Iraq would produce 1,500,000 bpd by the summer and return to pre-war levels of approximately 2,500,000 bpd by the end of 2003. Those forecasts were later adjusted and now range from between 1,500,000 bpd and 2,000,000 bpd by the end of the year. Although there have been conflicting reports in the press about the current level of oil production in Iraq, at the end of July 2003, most officials seemed to agree that production had increased to at least 1,000,000 bpd and, perhaps, is as high as 1,500,000 bpd. If this is the case, then Iraq should be able to meet both its domestic consumption demand and its export obligations under its term contracts.

One of the primary reasons for the uncertainty surrounding future production levels is that the export pipeline from the massive Kirkuk field in the north of Iraq to Ceyhan on the coast of Turkey has been the subject of repeated and ongoing sabotage, making it impossible to predict when that export route will become available. Because of this lack of an export route in the north of Iraq, production from the Kirkuk field remains relatively stagnant at approximately 500,000 bpd, even though its capacity is estimated at 1,800,000 bpd. Currently, the only production that can get to market is approximately 180,000 bpd for the Baiji refinery in the north. Associated natural gas is being siphoned off of the remaining production, which is then being reinjected because of a lack of export routes or storage facilities.

Production from the southern oil fields around Basra has been much more predictable, although not without difficulties caused by deteriorating infrastructure and ongoing security concerns. In June, the fields around Basra (including South Rumaila and North Rumaila, which have an estimated collective capacity of approximately 1,300,000 bpd) were producing only 350,000 bpd. However, by the end of July 2003, they were producing between 600,000 bpd and 700,000 bpd. As soon as the installation of pumping facilities at the Qarmat Ali water processing plant is complete — and, therefore, the reinjection of filtered water into the oil wells to improve the quality of the crude is possible — production is expected to increase to approximately 800,000 bpd. Of those 800,000 bpd, approximately 120,000 bpd will be allocated to the Basra refinery and 20,000 bpd will be allocated for the local power plant. The remaining amount will be available for export through Mina al-Bakr, the terminal in the Persian Gulf through which more than 1,000,000 bpd flowed during the United Nations' oil-for-food program. The predictability and flexibility of export availability from the southern fields is assisted by the existence of approximately 4,000,000 barrels of storage capacity in the region.

OPEC does not believe that enough Iraqi oil is coming to market to have a significant effect on oil prices.

Effect on Oil Prices

Iraq should earn approximately $2.5 billion in oil revenues (assuming a $25 per barrel price) from the 10 term contracts, if the oil production level is maintained at least at its current reported levels and the domestic consumption level does not increase substantially.

Some analysts have predicted that the inflow of Iraqi oil to the market would cause the collapse, or at least a dramatic decrease, in the price of oil, forcing OPEC to adjust its production quota to maintain the price within the target range it set of between $22 and $28 a barrel. However, at its meeting on July 31, 2003, OPEC decided not to change its output quota of 25,400,000 bpd. This decision indicates that OPEC does not believe that the increase of 600,000 to 650,000 bpd (approximately 2.5% of total OPEC output) of Iraqi oil on the market will have any real impact on the price of oil, or at least not cause the price to fall below the target range.

However, even if the price of oil remains stable at approximately $25 a barrel, Iraq must export substantially more oil to satisfy the expected oil revenues provided in its budget for the period July-to-December 2003. According to the Iraqi budget, oil revenues for the last half of 2003 are expected to be $3.455 billion, which would require the export of approximately 770,000 bpd for the entire six-month period at $25 per barrel. This budget was created by each Iraqi ministry and each Kurd region working with its coalition senior adviser. The budget was then discussed with the coalition finance adviser and reviewed by officials from the Iraqi Ministry of Finance and Ministry of Planning. Finally, the budget was presented to the US Agency for International Development and United Nations representatives and approved by the Coalition Provisional Authority Program Review Board.

Iraqi oil officials working with the US Army Corps of Engineers, Kellogg, Brown & Root and Halliburton estimated at the end of July that increasing average export capability to 770,000 bpd for the last half of 2003 will require an investment in the oil fields and infrastructure of approximately $1.6 billion. If this investment is made, the experts then suggested that sustained production capacity of 1,500,000 bpd should be reached by October 2003; 2,000,000 bpd by December 2003; and 2,800,000 bpd (its pre-war level) by April 2004. If the production capacity targets of this plan for 2003 are achieved, domestic consumption does not exceed approximately 500,000 bpd, and the price per barrel of oil is maintained at $25 or more, then Iraq should be able to earn the oil revenues called for in its budget for July-December 2003.

Iraq

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The first sales of Iraqi oil after the US invasion occurred in June and were made based on a tender for spot sales. ChevronTexaco won the right to buy 2,000,000 barrels of Basra light crude, to be lifted at Mina al-Bakr. Kirkuk grade crude that had been stored in Turkey since before the US invasion was sold to Turkey's Tupras (2,500,000 barrels), France's Total (2,000,000 barrels), Italy's Eni (1,000,000 barrels), Spain's Repsol-YPF (1,000,000 barrels) and Cepsa (1,000,000 barrels). According to the US administrator, Paul Bremer, the sale of those 9,500,000 barrels of oil resulted in $250 million of revenue. All of that crude was lifted by July 3, 2003, at which time the second tender for Iraqi oil was announced. The winners of that second tender were ChevronTexaco, BP, US trading house Taurus, and Royal Dutch/Shell, each of whom was awarded 2,000,000 barrels. A third round of sales at the end of July was for export of another 6,000,000 barrels of crude in total to ChevronTexaco, Petrobras (Brazil) and Vitol (Switzerland). ◎

Financing LNG Terminals

Spiraling natural gas prices led Alan Greenspan, the US central banker, to call in June for construction of more terminals for receiving liquefied natural gas, or LNG. The following are excerpts from a discussion in San Diego in June about whether LNG projects are a significant opportunity for the project finance market. The question was, "There is a lot of talk this year about new construction of receiving terminals, but how many of them can the country possibly need?"

The speakers are Geert Peeters, vice president—finance of Tractebel North America, Steven S. Greenwald, a managing director of Credit Suisse First Boston, Mehmet Muftouglu, finance director for ConocoPhillips, David Hodson, a former senior executive with BNP Paribas and now a principal with Dome Energy, a new company formed to develop, own and operate LNG projects, and Dan Rogers, who, before joining Chadbourne in Houston, was an associate general counsel at Enron with responsibility for LNG and other gas projects. The moderator is David Schumacher, a project finance lawyer who manages the Chadbourne office in Houston.

MR. SCHUMACHER: Let's start with Geert Peeters from Tractebel. Tractebel owns and operates an LNG terminal in Boston, and it is in the process of developing another terminal in the Bahamas that will bring gas into Southern Florida. What makes North America a good market for LNG?

MR. PEETERS: It would be too easy for me to say that Alan Greenspan is on our payroll. Indeed, this week he gave the answer to that question. Your country's most senior economist is convinced that there is a serious imbalance between the future gas needs of the country and current sources of supply. We felt the same thing a couple years ago when bidding on a proposed LNG terminal in the Bahamas.

Tractebel's interest in this market did not start with the Bahamas terminal. Tractebel invested in an LNG terminal more than 20 years ago in Europe. That was at a time when we felt that Belgium needed to have more diverse sources of energy supplies. It was after the Arab oil crisis.

Now, having terminals on both sides of the Atlantic, we are pioneering a little bit the view that LNG is not just a source of gas to resolve a local mismatch between demand and supply, but rather LNG is starting to become a real commodity — a real market. You get more and more liquefaction plants going up in the Middle East and they breed more projects in Europe and the United States. What that means, we think, is that we really see a commodity market coming and LNG will be treated more and more as a commodity.

We think this will lead, in turn, to some interesting developments on the financing side. Will we keep seeing integrated models of the terminals or will we see more and more merchant terminals? I had a problem saying the word for all the reasons you know. [Laughter.] But yes, we want to open people's minds about that.

When we bought the terminal in Boston, we thought all its "features" were actually very helpful. That terminal for many years has been sourcing its LNG, not just from one place and on the basis of long-term contracts, but over a portfolio of different terms and contracts and from at least two places. The LNG comes from Trinidad and Algeria.

That company as well has been owning ships on the one side, chartering ships on the other side, and also buying LNG ex-ship. In other words, it has also been diversifying on the logistical model. And last but not least, it has not only been buying LNG to sell in its Boston area, but also to resell in

Puerto Rico. It has been, to some extent, a pioneering merchant LNG business and so far financially very successful.

Key to Financing

MR. SCHUMACHER: Now that Geert has used the M word, let me turn to Steve Greenwald. A number of new receiving terminals are on the drawing board along the Gulf Coast all the way down to Mexico. If all of them were built, they would increase the receiving terminal capacity about five fold. Obviously, not all of these projects will be built. What makes one of these projects financeable? Does it need a tolling arrangement? Are these just fancy gas storage projects? Can the developers take any commodity risks and still get financing?

MR. GREENWALD: Commodity risk could mean a couple things to me. Some of the new contracts that are being contemplated are very simple to understand because someone is signing up for 500 million cubic feet a day at no more than 30¢. Trunkline refinanced a year and a half ago on the basis of a contract with British Gas for about 24 cents an mcf. It was very easy to understand looking at a contract. You knew what you had.

MR. SCHUMACHER: Twenty-four cents is the capacity charge?

MR. GREENWALD: Right. Some of the newer contracts that are being negotiated no longer stipulate X¢ per million, but rather require payment to the owner of the LNG terminal of something like 13%, 12%, or 15% of cost. With such projects, lenders might be asked to take some price risks. People are signing up. I don't think lenders will have too much heartburn evaluating the price risk and coming to a point of view as to what their cash flows will look like.

However, to ask a lender to finance a truly merchant LNG facility where you don't know where the LNG will come from or who will deliver the LNG is a different matter. If I am financing an expansion near Boston for Tractebel, I can come to a point of view as to Tractebel's ability to source LNG, to bring it there, even if there is no explicit contract to do so. It would be different looking at an LNG import terminal proposed by a developer who does not have that upstream capacity, let alone downstream capacity. I don't think we're there yet.

MR. SCHUMACHER: In other words, a project that lacks the backing of a Tractebel will need a binary contractual structure where both the sources of supply and the offtake arrangements are nailed down?

MR. GREENWALD: I certainly think you need it for so-called IPP developers or for someone just looking to set up an LNG terminal who has no upstream or downstream capability. Anyone developing an LNG terminal and thinking if he builds it, they will come, will find it hard to get any meaningful amount of financing.

The competition for LNG — once all the receiving terminals under development are built — will push up prices.

MR. SCHUMACHER: Even if it is just a tolling facility?

MR. GREENWALD: I thought the question was can you install a merchant energy facility, build it and, because Allen Greenspan says we need it, therefore lenders will take the view that the gas will show up? I don't see that happening.

Market Screens

MR. SCHUMACHER: Mehmet Muftuoglu, coming from the LNG world at ConocoPhillips, what criteria do you take into consideration when looking at a project, upstream or downstream? And does the North American market meet those investment criteria?

MR. MUFTUOGLU: As an upstream gas company, we like long-life legacy projects that generate stable cash flows or earnings for 20, 25 or 30 years. These are the projects that also allow us to book several hundred million barrels in reserves. Reserves are one of the most important factors in our project selection criteria.

The market becomes critical, especially on the gas side. If you look at our entire business, it is a global business. However, on the gas side, it is primarily a / continued page 48

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regional business at best. A capacity imbalance in the market becomes crucial so that you can generate acceptable revenues and know that there will be adequate demand. If you look at the US market from this perspective, we believe that the current supply and demand gap will continue for a long time. Of course, whether the gap is large enough to justify all of these projects is still unanswerable. But we think that there is a role to be played by LNG, and that's why we are looking at several LNG plants as well as bringing pipeline gas from Alaska and Canada.

MR. SCHUMACHER: David Hodson, Dome Energy Partners is also looking at developing LNG terminals. You are obviously not Tractebel or ConocoPhillips. Is there room in this market for smaller players?

MR. HODSON: The answer is yes. That is why Dome Energy Partners established itself very recently. We are an entity that has been formed to develop plants, fund plants, and own and operate LNG receiving terminals. We are focused on the US. We don't think gas producers and LNG producers want to own LNG receiving terminals. They basically want the gas moved from one place to a market where they can sell it.

MR. SCHUMACHER: Like the British Gas model in Lake Charles, Louisiana?

MR. HODSON: Right. Natural gas is turned into LNG so that you can move it long distances. It is sort of like wrapping up a package so that you can unwrap it when you get to wherever you transport it. At Dome, we believe that if people like ConocoPhillips and the Exxon Mobils and the Shells of the world had a reliable creditworthy entity that could basically unwrap the LNG and turn it back into gas, they would be very happy just to have the capacity. That is not to say that they wouldn't develop some of their own LNG terminals themselves. But at the end of the day, they want capacity, they want send-out rating, and they want storage. And they want it at a low cost.

The other aspect that we bring to the table is that we're looking at some innovative — what I call step — changes in the technology of regasification and storage and some more cost-effective means to do that. As the end of the day, I think we are better equipped to move quickly and to adapt and to innovate some of these ideas.

Tractebel has received 22 indications of interest so far from lenders interested in refinancing its LNG terminal in Boston.

MR. SCHUMACHER: Mehmet Muftuoglu, I want to pick up on your comment about the gas market being more regional compared to the oil market. Why can't you treat LNG terminals much like you treat a refinery and finance them like you would a refinery? Refineries don't need long-term contracts to be financed. Is the problem that the gas market is truly different than the market for refined oil products?

MR. MUFTUOGLU: I think as a company, we agree with Tractebel. In the longer term, we see the energy business — especially in the United States — as an acquired commodity business. We are not there yet. As to financing LNG terminals, the main issue is providing the capacity to the regasification plants. Unfortunately, they cannot be financed today without commitments. It may be cheaper for us to go out and do this on our own because we do not need project financing in the US.

Are There Enough Ships?

MR. SCHUMACHER: Dan Rogers, one of the keys to making this a truly liquid market or a commodity market is the shipping capacity to move the liquefied product to the end market. Will there be enough shipping capacity available to make it a truly liquid market?

MR. ROGERS: If you had asked me that question four years ago, I would have had some concern. I think the situation has reversed itself in the last four years. Today, we have a fleet of 140 ships. Of those 140 ships, 56 of them will be more than 25 years old by 2007. Of those 56, 34 will be more than 40 years old by 2007. There could be a rapid drop off in terms of the existing fleet. LNG tankers usually have a useful life of between 25 and 40 years.

The good news is that in the last several years, there has been a lot of activity in the shipyards, a lot of very aggressive shipyard bidding as well as some pretty significant reductions in steel prices. Today, we have 53 new builds underway. At the end of the day, I do not think the capacity on the shipping side will be a problem. More and more of the greenfield plants that are going into service are also financing the building of their own ships. That will add further to the available fleet.

MR. SCHUMACHER: The LNG market has operated in the past as a binary market. The gas supply is contracted to the ship which is contracted to the receiving terminal. In order to make it a truly liquid market, these bonds need to be broken. Can liquefaction be bought on a merchant basis to free up liquefied gas for trading?

MR. PEETERS: I think that we probably underestimate some market forces if we look at it only from the US. The US would like to see more LNG coming in, and it will try to foster that. When you are in the market today to sell LNG or to buy LNG for the US, you see that you are competing with European buyers. This pushes up prices. The competition among buyers is one of the things that accelerates the commoditization of LNG.

When you are selling LNG from the west coast of Africa or from the Middle East, you see that there are many more others who need it as well. As a seller, you compete with your peers on the coast, with seller in the Middle East, with Egypt and others in the Mediterranean basin, and with Trinidad and other places as well. We think we are in a very steep curve toward commoditization.

Financing Merchant Projects

MR. SCHUMACHER: Steve Greenwald had doubts about the financeability of many merchant terminals. How do you get the lending community comfortable with projects that do not have long-term contracts?

MR. PEETERS: We are in the market to refinance our Boston terminal, and I had to review 22 confidentiality agreements so far. There is a lot of interest from the lending community to lend to the business. It will be interesting to see if we can come up with creative structures where maybe they share in the upside to some extent in exchange for taking downside commodity risk to some extent. Maybe that is one way to start moving toward a buy and sell model, which we should get in a world of more commoditization of the LNG, as opposed to a tolling model which is — excuse me for being so blunt — a business of lending against spreadsheets.

MR. SCHUMACHER: Steve Greenwald, in light of what has happened to the merchant power market in the last several years, are credit committees ready to look at merchant LNG projects?

MR. GREENWALD: Nope.

MR. SCHUMACHER: Has your credit committee looked at any such projects?

MR. GREENWALD: Again, they will look at such a project for Tractebel, which has a history in the business. I guess we will. Now I know we're actually one of 22. I didn't know it was that bad. [Laughter.] But putting money into an existing facility like Everett is much different than funding a project on the Gulf coast or Baja for someone who has not heretofore been a player in the business. It is a much different analysis.

Let me put the question back to Mehmet Muftuoglu. Do you think ConocoPhillips will build a merchant plan for $3.4 billion? I doubt it — although a company is doing it right now. Exxon Mobil is doing it. It has a merchant facility, but it is taking the offtake and it is trying to land in the UK. Maybe lenders will take UK gas price risks. Exxon Mobil is the first to have announced anything of this sort.

We have been working the last couple years with Shell on two projects. Shell did not get permission to proceed with one of the projects on the basis that Shell would be able to find a market for the regasified product. They have anchor contracts in the Far East. Will they take some of it on a merchant basis and try to land it here in the States? Sure, they will try to do that. But only the Shells and the Exxon Mobils might try something like that. ConocoPhillips might try it, but for a small portion of an upstream plant. I don't see many of the big guys building real, real big facilities to be sold out on a merchant basis in the next five to seven years.

MR. SCHUMACHER: Liquefaction facilities have been built typically in partnership with government involvement. How do LNG purchasers get comfortable with the credit of these LNG liquefied sellers?

MR. GREENWALD: If you have a short gas supply, that could be an issue. Will you get the LNG? But if you have a gas supply locked in and it is coming from / continued page 50

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Trinidad or Algeria or wherever and you don't have to live with the creditworthiness of the owner of that LNG regas facility, it is a lot less critical. Think about the first AES power plant. Who was AES when it built its first plant? It didn't really matter, except everyone knew it had gas coming in under a contract, and there was a separate contract to sell to a credit-worthy purchaser. I don't think that's an issue. ◎

How To Construct a "Ring Fence"

by Kristin Meikle and Amy Nelson, in Washington

Many distressed power and telecoms companies are looking for ways to protect their profitable businesses and projects from the reach of creditors of the other parts of the company that are in distress.

One method for doing this is called "ring fencing." This article explains what ring fencing is, why it is done, how entities have been successfully ring fenced, and what risks and issues should be taken into account when considering whether a subsidiary can or should be ring fenced.

Ring-fencing structures sometimes attract bad press, but appear to be able to sustain judicial scrutiny. For example, a federal appeals court recently brushed aside objections from the state of California and upheld steps that PG&E Corp. — a holding company — took in early 2001 to isolate its regulated utility subsidiary, the Pacific Gas & Electric Company, in order to protect its other subsidiaries. The utility filed for bankruptcy three months after PG&E put the ring fence in place. Such financing structures have also met with some level of approval within the financial community. Standard & Poor's confirmed the efficacy of one such ring-fencing structure in late 2002 when it reaffirmed a strong credit rating for Portland General Electric Co., notwithstanding that the utility's parent — Enron Corp. — was in bankruptcy. The credit rating survived because Enron had set up a ring fence around Portland General, and there were powerful financial disincentives for the Enron creditors to force Portland General into bankruptcy.

What is Ring Fencing?

The phrase "ring fencing" refers to steps taken to make a subsidiary "bankruptcy-proof" or "bankruptcy remote." Ring fencing is supposed to shield the assets of the subsidiary from the bankruptcy of its parent or affiliates and allow the subsidiary to obtain or maintain a "standalone" credit rating substantially higher than the lower credit rating of its parent.

Ring fencing is used in a variety of financing situations, including acquisition financing, monetizing a subsidiary's dividend distributions, and corporate spin-offs. In the project finance context, ring fencing generally refers to implementation of two types of provisions: the requirement that an independent director or a separate class of stock be established for an entity to vote on voluntary bankruptcy filings, and the requirement that the entity observe "separateness covenants," such as maintenance of separate bank accounts and no commingling of assets. These types of provisions are implemented in order to guard against certain specific risks in the bankruptcy context, including the following:

- The filing of a voluntary bankruptcy petition by the governing body of the subsidiary.
- Substantive consolidation. Substantive consolidation is an equitable remedy that allows the bankruptcy court to pool the assets and liabilities of two separate but affiliated entities and to treat them as though they are the assets of a single bankrupt debtor. Courts will look at whether there is substantial identity between the entities to be consolidated, meaning whether the affairs of the parent and the subsidiary are so intertwined as to make the two entities essentially indistinguishable. They will also look at whether consolidation is necessary to avoid some harm or realize some benefit.
- The filing of an involuntary bankruptcy petition against the subsidiary by creditors of the parent or its affiliates, by creditors of the subsidiary or by the parent or its affiliates.
- Piercing the corporate veil. The "corporate veil" may be pierced if the subsidiary has acted as the "alter ego" of its parent, if the parent exerts more control over the subsidiary than would be expected of a normal investor, or if the actions of the parent directly caused the subsidiary to incur a liability. Piercing the corporate veil is a risk when the parent so disregards the separate identity of the subsidiary that their enterprises are seen as effec-

tively commingled. Creditors could pursue a form of "reverse" corporate veil piercing when the parent is insolvent and the subsidiary is viewed as a source of funds.

How to Ring Fence

There is no one blueprint that will guarantee that an entity is successfully ring fenced. However, there are at least six factors at which courts and rating agencies look in order to determine whether an entity is sufficiently "standalone" to justify shielding its assets from creditors of its affiliates (or, in the case of rating agencies, to justify a "standalone", investment grade, rating).

First, the new entity must be a single-purpose entity. Its objects and powers must be restricted as closely as possible to the core activities necessary to effect the structured transaction. This restriction reduces the entity's risk of voluntary insolvency due to claims or risks associated with activities unrelated to the structured transaction. It also reduces the risk of third parties filing involuntary petitions against the entity. These restrictions should be drafted into the entity's charter documents for two reasons: the charter documents are publicly available, and therefore serve as public notice of the restrictions, and the entity's management is more likely to refer to these documents, and therefore be reminded of the restrictions, when conducting its affairs.

Second, the new entity should incur no additional debt beyond what is needed for its routine business purposes. In order to limit the likelihood of an involuntary filing, the entity should covenant not to incur debt except where such action is consistent with its business purpose. This will reduce the likelihood of holders of additional indebtedness pursuing involuntary petitions to gain access to the entity's assets or cash. The entity's charter documents may also contain limits on the entity's ability to incur voluntary liens.

Third, the new entity should covenant not to merge or consolidate with a lower-rated entity. The bankruptcy-remote status of the subsidiary must not be undermined by any merger or consolidation with an entity not adequately protected from bankruptcy or by any reorganization, dissolution, liquidation or asset sale. The new entity should also covenant not to dissolve.

Fourth, the new entity should observe various "separateness covenants" in order to avoid being substantively consolidated with its parent. It should maintain separate offices from its parent, separate financial records and financial statements, its own corporate books and records, and separate bank accounts. There should be no commingling of assets with its parent or any of the parent's affiliates. It should pay its own liabilities and expenses. It should have adequate capitalization, given the nature of its business. Entities may also want to consider implementing restrictions on asset transfers and dividend declarations.

Fifth, the company should obtain a "non-consolidation opinion" from its counsel. A non-consolidation opinion addresses the likelihood that a court will grant substantive consolidation based on the observance by a parent and its subsidiary of the various "separateness covenants" referenced above.

Finally, the new entity should in its charter documents provide for either an independent director or a special class of stock (or "golden share"). The independent director or the owner of such class of shares should be an independent entity with no tie or relationship to the parent, its affiliates or any lender to the parent or affiliates. The charter documents of the subsidiary should require the affirmative vote of the independent director or the holder of the golden share before any voluntary filing into bankruptcy. It should also require the independent director or the holder of the golden share consider the interest of the subsidiary's creditors, in addition to the interests of the shareholding parent, when deciding whether to file. This factor is often viewed as critical by the rating agencies in order to insure that a standalone rating for the subsidiary is justified. Different entities have taken different approaches to this factor. For example, the California utilities have adopted the independent director approach. Under the corporate documents of these entities, a unanimous vote of the board of directors is required for certain major corporate actions, including the institution of bankruptcy proceedings, dissolution, liquidation, and the payment of dividends in excess of certain tests. Portland General instead established a special class of junior preferred stock that is held by an entity independent of Portland General and its affiliates and that requires the vote of the junior preferred holder before Portland General can voluntarily file for bankruptcy.

These factors are not in and of themselves bullet-proof. For example, courts will generally not compel compliance with the various covenant requirements. "Nonpetition" covenants — under which a parent agrees not to file a bankruptcy petition against the / continued page 52

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subsidiary — are typically not enforceable, as waivers or prohibitions on bankruptcy petitions are void as a matter of public policy. Non-consolidation opinions are fact specific, limited in scope and highly qualified; they also do not address the likelihood of the parent independently filing the subsidiary into bankruptcy. The "golden share" or independent director mechanism only addresses a voluntary bankruptcy situation. While the independent director or golden shareholder may prevent a voluntary petition, the risk that creditors will pursue an involuntary filing still exists. In addition, although it is accepted practice that once an entity is in the "vicinity of insolvency," the director's duties extend beyond the entity and its shareholders to include its creditors, the use of an independent director whose position is created specifically to look beyond the interests of the shareholders has seldom been tested in court. Some courts have indicated a willingness to ignore the independent director arrangement. At least one Delaware court permitted a corporation to file a voluntary petition in 1992 without the unanimous vote of the directors, contrary to the requirements of the charter documents. However, this holding appears to be the exception rather than the rule.

As a result, an entity should consider incorporating as many of the elements listed in this article as possible when contemplating a restructuring with the intent of ring fencing. (It should probably also opt for the golden share approach rather than the independent director approach.)

Other Issues to Consider

Although courts appear to be willing to uphold the ring-fencing structures established to date, and rating agencies have provided significantly higher ratings to ring-fenced entities than to their parent companies, because of the highly publicized nature of the Enron bankruptcy and other recent high-profile bankruptcies, ring fencing is subject to a high level of public scrutiny and is liable to be challenged again in the courts.

Because of this, there are a number of non-legal considerations to factor in to the decision of whether and when to ring fence.

Ring fencing is often perceived by the public as an attempt to hide assets that would otherwise be available to creditors. However, the companies doing the ring fencing suggest that they are restructuring their assets to maintain the viability of the company. The difference between hiding and restructuring may depend in part on timing — for example, whether the new entity was in place before or after the liabilities were incurred. PG&E Corp.'s timing was potentially more of a problem given that the restructuring occurred just three months prior to when its affiliate, Pacific Gas & Electric Company, filed for chapter 11 bankruptcy protection. Although this element has not yet appeared as a factor in the court's decision-making process, companies would be wise to begin the restructuring and ring-fencing process as soon as practicable, before their financial problems become dire.

There are at least six factors at which courts and rating agencies look when deciding whether to honor a "ring fence."

The restructuring effort may also benefit from how one "spins" the restructuring. For example, Edison Mission Energy received FERC approval for the restructuring of subsidiaries of Edison International over the objections of Exelon and others, in part because it stressed that the restructuring was necessitated by its need to meet certain financial commitments to the state of California. In its approval, FERC indicated that it was relying on fulfillment by Edison International of financial commitments it had made to the California Department of Water Resources and that the additional financing to be obtained would serve the public good. Consequently, when contemplating a restructuring to effectuate a ring fencing, companies should consider not only the implementation of various legal factors and the timing of the transaction, but also how they will tell their stories to the public. ◎

Environmental Update

Mercury

Mercury standards are on the horizon for coal and oil-fired power plants in a number of states. Federal standards will also be proposed by year end.

Connecticut has taken the first step in adopting such a standard. A new law that went on the statute books in early June requires mercury emission reductions of approximately 90% starting in 2008 from coal-fired power plants in the state. The state's two existing coal-fired plants are immediately affected. The new law provides the plants with the option of reducing mercury to a 90% control efficiency or meeting a .6 lbs/mmBtu mercury emission limit. Power plant owners in Connecticut will have the option of burning coal with a high mercury content and installing new pollution control equipment, such as an activated carbon injection system.

Meanwhile, the Massachusetts Department of Environmental Protection is working on a new regulation that would impose a similar 90% mercury emission reduction requirement on the six large coal-fired power plants in the state. The Massachusetts rule will be issued pursuant to a law that was enacted in 2001 and that called for substantial NO_x, SO_2, mercury and CO_2 emission reductions from the six oldest power plants in the state. The Massachusetts regulations are expected to require compliance with the new mercury standards by October 1, 2006.

New Jersey is also working on a proposed mercury reduction rule that would apply to utilities, iron and steel plants, and industrial boilers. The proposed regulation is expected to require mercury emission reductions of at least 90% from baseline levels. Compliance will be required by 2008.

The Wisconsin Natural Resources Board approved a mercury reduction rule at the end of June that calls for a 40% reduction in mercury from coal-fired utilities by January 1, 2010, and an 80% reduction by January 1, 2015 from a 2002 to 2004 baseline. The proposed Wisconsin rule is awaiting final approval by the state legislature.

New federal air toxics standards for coal and oil-fired power plants are expected to be proposed by December 15, 2003. They should become final a year later. The new standards are expected to focus primarily on mercury reductions.

Technically, the new rule will set state-of-the-art emission standards based on "maximum achievable control technology" or "MACT." This utility MACT rule will apply to major air toxics sources, meaning a plant that has the potential to emit 10 tons or more of any one hazardous air pollutant or 25 tons or more of any combination of such pollutants. The Clean Air Act includes a list of 188 hazardous air pollutants. The rule may force many affected plants to implement pollution control technologies to reduce mercury emissions starting in December 2007.

In drafting the new rule, the Environmental Protection Agency has been focusing on whether there will be subcategories of emission sources so that different mercury emission reduction levels apply to different types of plants. Power plants may be put into different subcategories depending on the combustion process used and the type of coal being burned. There are several different types of coal, including anthracite, bituminous, sub-bituminous, and lignite, and each type of coal has a different level of mercury content. There are also significant differences in the types of mercury within these coals. For example, divalent oxidized mercury is soluble in water and is more easily removed than elemental mercury, which is insoluble in water. Thus far, EPA has not tipped its hand on what subcategories it plans. The agency appears to be considering reductions in the range of 70 to 90% from a baseline of uncontrolled mercury emissions. In general, the higher the overall reduction targets, the higher the compliance costs for the utility industry as a whole.

A key concern is how to achieve mercury emission reductions when there is no one mercury reduction technology that can consistently achieve reductions on the order of 70 to 90%. Depending on the type of coal being burned, conventional pollution control technologies, including wet flue gas desulphurization scrubbers and baghouses, may achieve significant mercury emission reductions. However in other cases, conventional technologies may not work. Newly developing mercury removal technologies such as activated carbon injection are promising, but they have not been thoroughly proven. Installation of control equipment would also probably involve substantial ongoing operating and maintenance costs in addition to the / continued page 54

significant up-front capital outlays. The release of the proposed utility MACT rule later this year will bring the potential compliance costs into sharper focus and allow plants more effectively to evaluate compliance strategies.

EPA Reconsiders NSR Rule

In response to petitions from environmental groups and many of the northeastern and mid-Atlantic states and the state of California, EPA has agreed to reconsider portions of the final new source review or "NSR" rule that was issued in December 2002. The NSR rule was supposed to streamline certain pre-construction permitting requirements for new major sources of air emissions and major modifications of existing major sources.

On July 25, EPA agreed to reconsider five limited areas of the final NSR rule. It wants public comments within 30 days after notice is published in the *Federal Register*. A public hearing in Research Triangle Park, North Carolina will be held on August 14 on the areas under reconsideration.

There are three principal issues under reconsideration. The government is evaluating whether to allow sources to maintain "clean unit" status after an area is reclassified from "attainment" to "nonattainment" under one or more of the national ambient air quality standards. There are issues tied to the requirement to maintain records for a certain period of time after a physical change or change in the method of operation. Finally, there are issues tied to application of plantwide applicability limits or PALs. EPA is also considering new comments on a "supplemental analysis" it did of the potential environmental impacts of the NSR rule. The agency concluded in the supplemental analysis that the new NSR rule would cause greater emission reductions than the program it is replacing.

Several state attorneys general from northeastern and mid-Atlantic states and California filed suit challenging the December 2002 NSR changes. Several environmental and health-related organizations have also joined the litigation, and the cases have been consolidated into one lead case called *New York v. EPA* (DC Cir. No. 02-1387). A decision in the case is expected in 2004. Most of the same parties that went to court to block the new NSR rule have also asked EPA to reconsider major sections of the rule. The administrative and judicial proceedings are expected to move forward on parallel tracks. EPA is also continuing to evaluate several other issues that were raised in the reconsideration petitions, and the agency is obligated to determine whether to reject or act upon these other issues.

Elected officials in many northeastern and mid-Atlantic states have been outspoken critics of the new NSR rule. Massachusetts has even taken the drastic approach of returning administration of the prevention of significant determination or "PSD" portion of the NSR program back to EPA. The Massachusetts decision was in direct response to the new NSR rule, and now major industrial sources in the state will have to apply to EPA Region I for their PSD pre-construction permits. EPA announced the rescission of the 1982 EPA-Massachusetts PSD delegation agreement in a June 17 *Federal Register* notice. Other northeastern states with delegation agreements with EPA, including New York, are considering turning back administration of the PSD program to the federal government.

Clean Air Act Reforms

The House committee with jurisdiction over environmental issues held a hearing in July on the President's "clear skies initiative." It was clear from comments by committee members at the hearing that they do not plan any quick action on the Bush plan or any other proposals that would make significant changes to the Clean Air Act.

Meanwhile, in the Senate, the environment committee chairman, James Inhofe (R-Oklahoma), is committed to trying to send a clear skies bill to the full Senate later this year, but it is questionable whether he has the votes to get the Bush plan out of his committee.

President Bush's clear skies initiative calls for ratcheting down the level of acceptable nitrogen oxides, or "NO_X," sulfur dioxide, or "SO_2," and mercury emissions from power plants in a two-phase approach. The Bush plan would set nationwide caps of 2.1 million tons of NO_X in 2008, 4.5 million tons of SO_2 in 2010, and 26 tons of mercury in 2010. These caps would decline in 2018 to 3.0 million tons of SO_2, 1.7 million tons of NO_X, and 15 tons of mercury. Democrats in the Senate and House say the phase-in periods are too long and argue that the reduction levels should be more stringent.

Most observers doubt the clear skies plan can pass Congress before the next presidential election at the end of 2004. EPA is reportedly working on a backup plan. The agency is considering issuing a new "fine particulate matter transport rule" that would be proposed next spring in the event that Congress has failed to pass the clear skies bill by then. EPA's fallback position is to use existing legal authority to propose reductions in power plant NO_X and SO_2 emissions that contribute to fine particulate matter or PM2.5 problems in downwind states. The proposed rule would be designed to reduce PM2.5 precursor emissions and assist states in achieving compliance with the PM2.5 ambient air quality standard that is in the process of being implemented. In 1997, EPA adopted a new PM2.5 national ambient air quality standard, and the standard has withstood a legal challenge from potentially-affected industry groups.

EPA is in the process of designating areas in "nonattainment" with the PM2.5 ambient air quality standards. Based on preliminary monitoring data, EPA expects 173 counties to be out of attainment. Many of those counties are reportedly affected by upwind fine particulate matter sources. States are required to submit plans for meeting the standards by 2007, and the PM2.5 air quality standard generally must be met between 2009 and 2015. EPA's fine particulate matter transport rule would be similar to the so-called NO_X SIP call rule. If proposed next spring, EPA would expect to finalize the new fine particulate matter transport rule by 2005.

The adoption of a fine particulate matter transport rule would achieve some of the goals of the President's clear skies initiative. However, it would not address mercury emission reductions.

Regional CO_2 Reductions

New York Governor George Pataki (R) is spearheading an effort to adopt a state-led regional approach to reducing carbon dioxide or CO_2 emissions from power plants. The governor announced in late July that 10 northeastern and mid-Atlantic states have agreed to work together on a cap-and-trade program to reduce CO_2 emissions.

The governors of Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Rhode Island and Vermont have pledged to work with Pataki to develop a regional strategy for reducing CO_2 emissions from power plants. The governors are expected to use the federal acid rain program as a model for their regional CO_2 cap-and-trade program. Discussions on how to implement such a program are expected to start in September 2003 with the goal of reaching agreement by April 2005.

In June, Maine became the first state to adopt a comprehensive statewide climate change law. The law would regulate a broad range of industries, including power plants and paper mills. The law requires Maine to develop a climate change action plan to reduce greenhouse gas emissions, including CO_2, to 1990 levels by 2010. It requires a 10% reduction below 1990 levels by 2020. The Maine statute is intended to implement Kyoto protocol-type reduction requirements. The Kyoto protocol is expected to be implemented in European Union countries, Canada, and Japan after Russia ratifies the protocol either later this year or early next year.

In related news, three New England states — Connecticut, Maine and Massachusetts — have filed suit in federal district court in Connecticut charging that EPA failed to regulate CO_2 under section 108 of the Clean Air Act. The lawsuit claims that EPA must recognize CO_2 as a criteria pollutant and regulate it under a national ambient air quality standard.

A similar lawsuit is pending in a federal district court in northern California. Environmental groups claim in that suit that EPA must regulate CO_2 under section 111 of the Clean Air Act. That section sets new source performance standards. The Bush administration argues that CO_2 is not a covered pollutant under the Clean Air Act and, therefore, is not subject to regulation under either section 108 or 111.

NSR Litigation

New source review litigation continues to be active with a number of recent developments in cases where the US government charges that utilities modified older power plants without undergoing a new source review analysis and permitting procedure. Many older power plants built before 1970 were exempted from changes in the Clean Air Act in 1970 and 1972. However, utilities must exercise care not to modify older plants significantly so as to bring them under the NSR permitting scheme. In 1999 and 2000, the US government filed suit against several utility companies with coal-fired power plants charging that the utilities made equipment changes or upgrades over the years that did not qualify as exempted "routine maintenance, repair, and replacement." In another NSR case, a US appeals court ruled that EPA acted unconstitutionally in issuing an administrative compliance order against the Tennessee Valley Authority. The court said that TVA was denied due process since such orders are not subject to judicial review. The court did not reach the issue whether TVA */ continued page 56*

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had in fact violated NSR permitting rules. The decision has cast considerable doubt on a standard Clean Air Act enforcement tool used by the agency. EPA is expected to refile its NSR case against TVA in federal district court. The agency may also appeal the US appeals court decision to the Supreme Court.

The TVA decision would not have any direct effect on the federal government's other NSR cases which were filed in US district courts. Several of the high-profile utility enforcement cases are expected to be decided in the next few months. At the end of June, a four-week trial of the liability phase in *United States v. Illinois Power Co.* was completed. The Illinois Power case involves the status of a number of construction projects carried out between 1982 and 1994 at an Illinois Power plant in Baldwin, Illinois. A decision is expected on the liability issues later this year and, if necessary, a trial in the damages phase will be scheduled for the beginning of next year. A decision is also soon expected in *United States v. Ohio Edison Co.*, a case involving Ohio Edison's alleged failure to undergo NSR permitting for plant upgrades at its Sammis power plant.

One other key case recently settled. After a federal district court rejected a number of affirmative defenses raised by Southern Indiana Gas and Electric Co., the parties agreed that the utility would spend about $30 million in pollution control technology and other plant upgrades to reduce air emissions at its Culley power station. The utility agreed to upgrade its oldest unit by repowering it with natural gas. It will also pay a $600,000 penalty and spend approximately $2.5 million on an environmental mitigation project.

Brief Updates

Twelve leading banks have adopted the "equator principles," a series of voluntary guidelines for addressing environmental and social issues in project financings of infrastructure projects in emerging markets. The equator principles apply to projects with a total capital cost of at least $50 million. The guidelines are based on standards that the International Finance Corporation — an arm of the World Bank — already uses in deciding whether to provide financing for private-sector projects. The banks are now to apply the same guideline to their own loans.

President Bush has named Marianne Lamont Horinko as the acting EPA administrator. Ms. Horinko had been the assistant administrator for solid waste and emergency response. The Bush administration has put off announcing a permanent replacement for Christine Todd Whitman, although there are rumors that the new agency head will be former Idaho governor Dirk Kempthorne. Several environmental groups are already actively opposing Kempthorne. No matter who is appointed, the Senate confirmation is expected to be contentious.

EPA has proposed an increase of 14.8% in the maximum penalties could seek for civil violations of environmental statutes. The penalties are being adjusted for inflation. For example, the current maximum penalty of $27,500 per day for a violation of the Clean Air Act will be raised to $32,500 a day per violation. The new penalties are expected to take effect later this year.

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