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PROJECT FINANCE

NewsWire

December 2004

The Next Agenda

Chadbourne held a conference call on November 12 to talk about what a Bush second term will mean for the project finance community, what energy and tax changes to expect in the coming term and what to do differently in deals in anticipation of these changes. Three panelists from Washington spoke for five minutes each at the start of the call, and then the audience asked questions. The panelists are Eugene Peters, chief lobbyist for the Electric Power Supply Association, the trade association for the US independent power industry, Keith Martin with Chadbourne in Washington, and Jonathan Weisgall, vice president for regulatory and legislative affairs for MidAmerican Energy Holdings Company, a holding company for electric and gas utilities that serve parts of Iowa, Nebraska, Illinois and South Dakota and for gas pipelines that serve the western United States and Texas. MidAmerican is also active in developing wind farms and geothermal projects. Two other Chadbourne lawyers — Adam Wenner and Roy Belden — helped answer questions.

MR. MARTIN: Jon Weisgall, what are you telling management to expect in the next year or two now that the Bush administration has been returned to office and now that the Republicans have larger majorities in both houses of Congress?

Energy Bill?

MR. WEISGALL: One caveat: these are my views. I am not speaking for MidAmerican.

Let me start with politics and timetables and then turn to / continued page 2

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EARNINGS REPATRIATION is receiving attention in corporate finance departments.

US companies have a limited time through the end of next year to repatriate earnings they have parked in offshore subsidiaries and pay US tax at only a 5.25% rate. The earnings must be repatriated in cash. Since most offshore subsidiaries redeploy their earnings in other investments, some companies are looking at borrowing money in order to pay cash dividends. Any earnings repatriated to the US must be reinvested in the US "including as a source for the funding of worker hiring and training, infrastructure, research and / continued page 3

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substance. On votes: first of all, the House of Representatives is largely unchanged, and there is room for debate about what the new 55-vote margin the Republicans will hold in the Senate means. Senator George Allen (R-Virginia) was quoted as saying, "We have more than enough votes for an energy bill." I don't see the count that way. I see an increase of perhaps one net vote for something that looks like the energy bill that the Bush administration tried unsuccessfully to put through the current Congress.

On process and timetable, let's talk about the House, Senate and White House in that order. Joe Barton (R-Texas), the chairman of the House Energy and Commerce Committee, is saying he will not do a comprehensive energy bill next year. He is tired of waiting for the Senate to reach a consensus on what it can accept. His committee has other issues on its agenda, like the reauthorization of the Clean Air Act. The key question is where is the House leadership? Are we going to see continued record prices for coal, gasoline, natural gas and oil and, if so, will they force action? These are open questions.

On the Senate side, Joe Barton's counterpart, Pete Domenici (R-New Mexico), chairman of the Senate Energy and Natural Resources Committee, was quoted by a spokesperson as saying, "We are going to start from scratch next year." I don't think this is a formula that will lead to an energy bill early in 2005, and with tax reform, social security reform and health care issues also pressing for attention, energy may find itself lost in the shuffle.

Turning to the White House, energy should be a high priority, but the Bush administration did not take a hands-on approach to energy during its first four years in office. We all heard President Bush say in his press conference two days after the most recent election, "I think I earned capital in the campaign, political capital, and now I intend to spend it." That may indicate a more assertive White House in the next couple years.

Moving to substance: I think the Republican leaders in the House will stick pretty much to the energy bill that failed to pass the current Congress. At the same time, we will see a more aggressive push on the supply side by the Senate. There may be some small changes around the edges of the electricity title in the bill, but the three core components remain reliability of the transmission grid, repeal of the Public Utility Holding Company Act and backstop siting authority of transmission lines for the Federal Energy Regulatory Commission. We will see another push on opening up the Alaska National Wildlife Refuge to oil drilling. I don't think ANWR drilling will make it into any energy bill that is enacted. Congressional leaders could try to use something called the budget reconciliation process in the late spring to move ANWR. The attraction to them of the budget process is a proposal needs only 51 votes to clear the Senate instead of the normal 60 votes that it takes to break a Senate filibuster.

I will defer to Keith on tax issues, but everyone note that Judd Gregg (R-New Hampshire) is taking over as chairman of Senate Budget Committee. Gregg will bring pressure to cut the deficit in half without raising taxes over the next four years. The new watch words will be fiscal restraint.

Moving to the challenges facing the next Congress: one is settling the MTBE issue that caused the energy bill to stall in the current Congress. The issue is whether to limit the liability of producers of a gasoline additive from MTBE from lawsuits. Another challenge will be to hold the electricity title together. There are several stakeholders who would like to make changes in the electricity language in the energy

It is not clear that Republicans picked up enough additional seats in Congress to pass a national energy bill.

bill. They would like to make what they think are improvements. The electricity language struck a delicate balance among competing interests. A third challenge will be domestic natural gas production. There is a welcome bipartisan initiative being led by Senators Tom Carper (D-Delaware) and Lamar Alexander (R-Tennessee) to look not only at how to increase the domestic supply of natural gas, but also at two other pillars: energy efficiency and fuel diversity. We may see some interesting proposals.

Another challenge is how to increase the fuel supply in an era of huge budget deficits and fewer dollars available for tax subsidies? Tax incentives are an easy way to take care of the issue. It will be harder to increase supply when the only tool the government has left in its tool box is opening up certain federal lands for exploration and drilling.

Another challenge is on the nuclear side. Pete Domenici is already out of the starting gate pushing for more incentives for the nuclear industry. He will run into a roadblock named Harry Reid, the incoming Senate minority leader from Nevada and a strong opponent of anything nuclear. Nevada is the national repository for nuclear waste. Another challenge is how to encourage imports of liquefied natural gas. Lee Terry of Nebraska is one Congressman who is already working on a bill to streamline permitting regulations.

Turning to environmental issues, the Bush administration has a "clear skies" initiative. It was proposed some time ago and has never made it out of a subcommittee in Congress, let alone a full committee or the full House or Senate. Maybe we will see movement. It will depend on the ratio of Republicans to Democrats on the key committees next year.

Climate change: even though this administration will be under mounting national pressure to take action, I do not see any progress anytime soon. The key question for the Senate Democrats is: Do you want to make a deal? You have some pretty challenging elections coming in 2006. You have a lot of freshmen Senators running for reelection as well as some older Senators like Daniel Akaka (D-Hawaii), Robert Byrd (D-West Virginia), Ted Kennedy (D-Massachusetts) and Paul Sarbanes (D-Maryland). The freshmen who will be up for reelection include Bill Nelson (D-Florida), Ben Nelson (D-Nebraska), Maria Cantwell (D-Washington), Tom Carper (D-Delaware), Mark Dayton (D-Minnesota) and Jon Corzine (D-New Jersey), who is already saying he may run for governor. The question for the Senate / continued page 4

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development, capital investments, or the financial stabilization of the corporation for the purpose of job retention or creation." There is no time limit on the reinvestment.

Congress left many unanswered questions. The Internal Revenue Service is expected to issue a series of notices, no later than mid-January, with more guidance.

Questions are being asked about the requirement that the earnings must come back in cash. A foreign subsidiary can borrow to raise the cash, but not from affiliates. Any increases in shareholder or other related-party debt of offshore subsidiaries between October 3, 2004 and the end of the tax year in which the lower rate is being claimed are potentially a problem.

One question is whether there will be any limits on a subsidiary's ability to borrow from banks to raise cash. Another question is whether the US parent can guarantee a loan from a bank to its offshore subsidiary. Many tax counsel are wary of such guarantees in situations where the subsidiary could not have borrowed on its own (as opposed to where it can borrow but the guarantee gives it a lower interest rate). A technical corrections bill introduced on November 19 in Congress would bar a US parent from "effectively funding" the dividends back to itself by making capital contributions or through other means.

Another set of questions revolves around the requirement that the money must be reinvested in the United States. Hal Hicks, an IRS associate chief counsel, suggested the IRS has tentatively concluded that the US parent company can use the cash to repay debt. However, the only substantive effect of raising cash by borrowing offshore and using it, after repatriation, to repay parent company debt is to shift debt offshore. Whether cash can be used to repurchase shares is still unclear. Also unclear is whether the cash can be used to make acquisitions. At a minimum, to the extent a target company has large foreign operations, the repatriated / continued page 5

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Democrats is whether they want to do a deal now or push this farther into the future.

The question for the Republicans is: How much do you want to get your agenda done? You succeeded in defeating Tom Daschle (D-South Dakota), which has implications for the energy bill since Daschle was a supporter. Is now the time to go for energy, and how are you going to get the House, Senate and White House to go along? I don't think an energy bill is inevitable next year, notwithstanding the conventional wisdom that it should now be a slam dunk after the latest elections. I think there has been only a modest increase in support.

The Republicans in the two houses are still not on the same page on procedure for how to get the energy bill done. The environmental issues are going to be brutal again. ANWR has a decent chance of getting done, if it can be done as part of a budget reconciliation process, separate from an energy bill.

Finally, I did not mention the Alaska natural gas pipeline project because the current Congress pretty much legislated all the incentives necessary to move that project forward, with the possible exception of price supports.

MR. MARTIN: Gene Peters, Jon Weisgall says he thinks the election will bring just one more vote for an energy bill. Are you as pessimistic about its prospects, and what else should one expect in the next year or two?

MR. PETERS: Jon did a superb job of summarizing a wide range of issues that should be of interest to the people on the call. I will try to avoid being redundant, but it may be hard.

Last year, the Republican vote counters in the Senate figured they needed just three more votes to get an energy bill, and that is because Senator Ensign (R-Nevada), who initially voted for the bill, then said he was going to vote against it. A key Republican staffer said recently that he thinks the Republicans picked up three votes for the energy bill in the November election. I do not think that is right. My own view is the bill picked up one or two votes, but not three. The next question is do the Republicans really need only three votes to pass the bill, or does a three-vote gap really mean that four votes are needed. The jury is still out.

The real question is why passing an energy bill is so hard when the energy plans presented by the two political parties have 80 or 90% overlap.

Let me review a number of topics on which Jon Weisgall touched briefly. Jon mentioned the MTBE controversy and incentives for nuclear power. It is hard for me to imagine that Joe Barton, the House Energy Committee chairman, will let big pieces of the energy bill move forward without a resolution of the MTBE issue. At the same time, it is hard for me to imagine that Pete Domenici, Barton's counterpart in the Senate, will let big pieces of the energy bill move without a few things that he wants. One of them is new production incentives. Barton said that he will not try to do an energy bill again next year; he was worn out by the last effort to pass the bill. I would not read a lot into that. The House can pass an energy bill any time it wants. I think all Barton is saying is the bill will not be a priority for him until the Senate acts. You cannot fault him for that position, given how the bill always grinds to a halt in the Senate. If the Senate acts, then the House will pass the bill and Barton could end up chairman of the conference committee that would be appointed to iron out differences between the House and Senate versions of the bill.

The only way an energy bill can pass the Senate is if it reflects the geography of the Republican caucus. Right off the bat, the Senate Energy Committee staff have said the committee will not simply repackage the bill that failed to pass the current Congress and put it to another vote. The committee plans to start over. The chairman, Peter

Domenici, has been talking about trying a more bipartisan approach the next time. The way the last energy bill was constructed was by looking primarily to Republican caucus and what had to be in the bill to line up the required number of votes.

With hindsight, that was a losing strategy. The temptation will be to try to do the same thing again now that there are more Republicans in the Senate. That may prove a losing strategy again.

One thing to keep in mind is that both the chairman and the ranking Democrat on the Senate Energy Committee are from the same state, New Mexico. The chairman is Pete Domenici. The ranking Democrat is Jeff Bingaman. If Domenici is serious about undertaking a more bipartisan effort next time, one would think it should be easier for two New Mexicans to do. Early signs are good. The Republican and Democratic committee staffs are starting to talk to each other for the first time in months.

Two other items: we pay a lot of attention at the Electric Power Supply Association to the relationship between Congress and the Federal Energy Regulatory Commission. You have a FERC commissioner — Suedeen Kelly — whose nomination to serve a second term is being held up by the Senate. The hold has nothing to do with her and everything to do with a dispute involving the Nuclear Regulatory Commission. Negotiations are underway to free her nomination. [*Ed.—The Senate confirmed Ms. Kelly to a second term in late November.*] The term of the FERC chairman, Pat Woods, ends in June. The conventional wisdom is that he cannot be confirmed again. I think that may be wishful thinking. It would not be easy for him to be confirmed for another term, but he still seems to have the backing of the Bush administration. The point is you have holes developing on the commission. FERC is already short one commissioner, even before the troubles for Suedeen Kelly and Pat Woods.

The other thing I want to talk about is the interaction between FERC and Congress. There were tensions during the first Bush term.

The commission has been in favor of regional transmission organizations, or RTOs. This has put it at odds with a Republican caucus in Congress that leans heavily toward the South and West in terms of its geographic interests. The commission will find it more difficult to do the things that still need to be done on market power mitigation, RTO development and similar core issues in */ continued page 6*

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earnings could not be used to pay the portion of the purchase price attributable to the foreign operations.

Questions have also been asked about a statement in the new law that "[n]o deduction shall be allowed for expenses properly allocated and apportioned" to the repatriated earnings. Companies have been asking what tax deductions they will have to forego in order to take advantage of the 5.25% rate. For example, current tax rules require US companies to treat part of the interest they pay on purely domestic borrowing as a cost of their foreign operations in the same ratio as their assets are deployed at home and abroad. The questions were answered by the draft technical corrections bill that was introduced in Congress on November 19. The bill would only rule out deductions that are "directly allocable" to the repatriated earnings. The chairman of the Senate tax-writing committee, Senator Charles Grassley (R-Iowa), said in a "colloquy" — or an exchange on the Senate floor with another Senator — that the intention was only to deny deductions for expenses that were directly related to the earnings being brought back to the United States. Thus, Grassley said, deductions for interest, research and development costs, state and local income taxes, general sales and marketing costs, and depreciation and amortization would not be affected.

A company must repatriate more earnings to the US than it did each year on average during a base period. The 5.25% rate applies only to the "excess" repatriation. Calculation of the base period repatriations is complicated in "US sandwich" cases where the US company has both a foreign parent and foreign subsidiaries.

A MUNICIPAL UTILITY cannot be given an interest in a power plant or sold a turbine that is already under construction without tax complications.

Municipal utilities */ continued page 7*

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the face of a lot of potential pushback from the Senate Republican caucus. There are several Texans in key leadership positions in the House, which probably helps Pat Wood in his dealings with the House, but the Senate is not a friendly place for him and he will have to pay close attention to what the Senate wants in setting his agenda, particularly if he wants to serve another term.

Any energy bill that passes will repeal a 1935 law that has been a barrier to consolidation of US electric and gas utilities.

Tax Simplification

MR. MARTIN: Gene, thank you. Let me speak briefly about what to expect on the tax front, and then we will open the floor to questions.

President Bush has made simplifying the US tax code a central theme of his second term. There is considerable skepticism in Washington about whether tax reform will occur at all and, if it does occur, whether it can be done quickly. The President also talked about tax simplification during his last campaign in 2000, and the Treasury Department produced an options paper two years ago, but there was no followup.

Pamela Olsen, who was the assistant Treasury secretary for tax policy in the Bush first term, warned in a cover memo to the US Treasury secretary in 2002 when she delivered the options paper that any overhaul of the US tax code is likely to have "vocal losers and largely silent winners." She also noted that adoption of a consumption tax, which is a favorite of Republican conservatives, has led in other countries to election losses for the incumbent party.

One can speculate endlessly about the prospects for major tax simplification. Here is all that can be said today as fact.

First, the President plans to name a bipartisan panel before the year ends to look at options for a major overhaul, with instructions to report back as soon as possible in 2005.

Second fact: the overhaul is supposed to be revenue neutral.

Third, the deductions for mortgage interest and charitable contributions are off limits and, fourth, the administration wants to tax consumption and reward investment, or as Bush said during his news conference on November 4, he wants to reward risk taking.

The bipartisan panel will probably use the Treasury options paper from two years ago as a starting point for its discussions. There were five options in that paper, but they distill essentially to just three broad approaches for business. One recommendation was to tax businesses on their gross receipts after certain deductions. For example, a business would tally up its gross receipts, deduct the cost of the goods it purchased from other companies, deduct the wages it paid, and that would be its tax base. It would not be allowed to deduct interest. Alternatively, the Treasury suggested keeping the existing income tax, but taxing corporations on the book income that they report to shareholders, stripping the system of most tax credits and deductions and reducing the tax rate. Dividends, interest, rents and royalties would not be taxed to recipients. The third broad approach in the Treasury options paper is to impose a value added tax — either in conjunction with the existing income tax or as a replacement. Value added taxes are common in Europe and other countries. They operate something like a national sales tax.

Tax simplification will be complicated by two realities. One is that House Republicans will be pushing early in the next year to make permanent three so-called middle class tax cuts that President Bush bragged about during the campaign. They are scheduled to expire in 2010. Making them permanent would add another $2.2 trillion to the national debt through 2014. That would increase the US debt by one third. The second reality is there are 22 tax breaks that expire at the end of next year, and the corporate tax bill that the President signed just three weeks ago added another 26 tax breaks that will expire between 2006 and 2010. There will be pressure to extend them.

What should one conclude from all of this?

My own guess is that major tax changes, if they are to be made, are a 2006 item. The second conclusion is whether there will be a significant overhaul in the US tax code depends on whether a consensus develops about what to do. It is too early to tell whether a consensus is even possible. Third, the Bush administration will have a hard time selling any tax overhaul that reduces taxes further on investment income while taxing consumption more heavily. The distributional effects of this are not very appealing.

Wind developers, geothermal developers and owners of other renewable energy projects will be pushing next year for an extension of production tax credits for their projects. There is not the money, given other priorities, to make these tax subsidies permanent. I do not see an extension until late summer at the earliest, unless it is part of an energy bill that moves earlier in the year.

Any significant overhaul of the US tax system would change how companies raise capital and how projects are financed. For example, if interest is no longer deductible, which would be the case under most of the Treasury options, but interest and dividends are not taxed to the recipient, would there be any need for the tax-exempt bond market? Probably not. Schools, roads, hospitals and other public facilities would lose the advantage they possess today in competing for capital. The balance between debt and equity would shift. Borrowing may be less attractive. Corporate capital structures and financing strategies would have to be re-thought.

Finally, the corporate tax overhaul, if it occurs, could also reduce or eliminate the benefit companies receive from existing tax subsidies — for example, for investing in renewable energy projects. Institutional equity investors putting money into such deals would be wise to take the risk of major tax simplification into account in their pricing and, in some deals, they may want to leave themselves an out. There are always transition rules when Congress changes the tax laws dramatically, but it is hard to preserve the full value of these tax breaks in a transition to lower tax rates.

Let's open the floor to questions. The / continued page 8

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must be careful when buying equipment not to buy any that has already been "used (or held for use)" by a private company in connection with a power plant or other "output facility." The problem with buying such equipment is the municipal utility may have a hard time using funds borrowed in the tax-exempt bond market to make the purchase. Most municipal utility borrowing is in the tax-exempt bond market. It may be hard to segregate where a municipal utility's money has come from.

Congress said when it enacted these rules that a power plant is considered "held for use" — even if it has not been put into service — if it was built for an investor-owned utility or independent power company.

An independent power company ordered four turbine-generator sets, but then realized it had no use for them. A municipal utility put out a request for proposals to turbine suppliers. The independent power company made the low bid to supply the municipal utility with the turbines the utility needed. It did so by assigning the contract with its manufacturer.

The turbines were in the early stages of assembly at the time at the factory and no components had been delivered yet to the project sites.

The IRS confirmed in a private ruling that the agency made public in late November that the turbines could be sold to the municipal utility because they were not yet "held for use" An important factor in the decision was that the turbines were not customized, but were "mass-produced" turbines using a standard design. The ruling is PLR 200448017.

The ruling is important for project developers who are having a hard time finding utilities to sign long-term contracts to buy electricity from projects on which they are working in the US. Without such contracts, the projects are very difficult to finance. Some developers have turned to trying to stitch together a series of smaller contracts with municipal utilities and electric cooperatives. Such / continued page 9 *continued from page 7*

way to ask a question, because we have so many people on the call, is to send the question by email. Questions have already been coming in while the panelists were talking. Let me ask Jon Weisgall, you are not very optimistic about the prospects for an energy bill next year. Isn't the real problem lack of a consensus in Congress about what to do?

FERC will have a hard time making further headway on promoting RTOs with a Republican Congressional caucus that leans heavily toward the South and West.

Energy Crisis?

MR. WEISGALL: Congress acts only in two situations: crisis or consensus. You would have thought the blackout in August 2003 in the northeastern US and Canada would have galvanized Congress to respond to crisis. It did not happen.

Congress has been looking at energy legislation for six years. Several of those years were when the Senate Energy Committee had a Democratic chairman, Jeff Bingaman (D-New Mexico). Then we had Frank Murkowski (R-Alaska), who left to become governor of Alaska, and then Pete Domenici (R-New Mexico) took over. The Democratic and Republican energy bills proposed during the last six years have a lot of overlap, probably 85 to 90% overlap, so there is a great deal of consensus.

I think the single biggest problem last year, when there was a close vote, was poor political timing. The Medicare bill had just passed, and the idea of handing President Bush two legislative victories in such a short period did not appeal to Democrats. The vote on the energy bill in the Senate was very close. You had a lot of Democrats from the Midwest who wanted a bill because of the ethanol provisions. You had about a 90% consensus, but politics got in the way.

The issue next year will be whether the different interest groups are willing to show enough flexibility to overcome the remaining 10% gap.

MR. MARTIN: Gene Peters, is another problem that there is no agreement on whether there is even an energy crisis that needs to be addressed?

MR. PETERS: I don't think that is the problem. The real question is: Why is this so hard? Jon is exactly right. If you look at what the Bingaman energy bill looked like when it was crafted by Democrats, and compare it to the Domenici bill, it is at least 80% the same stuff. I think the real problem has been the partisan rancor in Congress. The situation was not helped by the way the last energy bill was put together. I actually think the next Congress will pass an energy bill. I just don't think it will happen quickly.

MR. MARTIN: In 2005? In early 2006?

MR. PETERS: The problem with Congress is that it works on a two-year cycle, and once you get past late spring of the first year, everything slows down. An energy bill will either get done very early in 2005 or not until 2006.

PURPA and PUHCA

MR. MARTIN: Jon Weisgall, if there is an energy bill, will it repeal PURPA — the 1978 law that requires electric utilities to buy electricity from independent power producers?

MR. WEISGALL: That's very interesting. As I mentioned earlier, there are three fixed components in the electricity title of the bill. They are backstop siting authority for transmission lines for the Federal Energy Regulatory Commission, PUHCA repeal and reliability. Repeal of the PURPA purchase requirement is also part of the electricity title. The electricity title was a bit of a third rail in the early years of energy bill consideration. It has become less controversial over time. It is no small feat that all the major stakeholder groups — rural electric cooperatives, municipal utilities, investor-owned utilities — came together and crafted an electricity title that includes PURPA repeal. PURPA repeal is a big issue for the investor-owned utilities and, in the interest of full disclosure, it is a big issue for my own company.

So to answer the question, if an energy bill is enacted, or even if pieces of the bill are enacted as separate measures — for example, an electricity measure, a separate nuclear energy bill, a separate natural gas bill — then I think PURPA will be repealed.

MR. MARTIN: Gene Peters, is the independent power industry fighting against PURPA repeal?

MR. PETERS: No and, in fact, a number of our members would like to see it repealed. I agree with Jon: if an energy bill is enacted, then PURPA repeal will be part of it.

The only thing I would say is that if I were Pete Domenici and I were serious about making the process more bipartisan, then the easiest way to do it would be to give in to the enhanced FERC merger review authority that Jeff Bingaman wants in exchange for PURPA repeal. FERC has had to wrestle recently with a number of proposed sales of generating plants to investor-owned utilities. At least one transaction was structured in a way that the participants thought would avoid any kind of FERC review. Some FERC commissioners were unhappy about the situation and would like the commission to have broader authority to review such transactions. The issue is now part of the electricity equation. Bingaman has made broader authority for FERC his price for going along with PURPA repeal. It is something that Domenici will be considering.

MR. MARTIN: Let me bring Adam Wenner into the conversation. Adam, many people have thought that a 1935 law called the Public Utility Holding Company Act — or PUHCA — was a barrier to stitching together a multi-state power company. Do you have a view on whether this law will be repealed, and does it really matter whether it is repealed? Haven't people found ways to work around it?

MR. WENNER: I defer to Gene and Jon on the prospects for repeal, but repeal would have a significant effect on US utilities. The reason that acquisitive US utilities want PUHCA repealed is so that they can acquire more than passive interests in other utilities, or more than 5% of the voting securities of other US utilities, and realize the economies of scale that other businesses achieve by expanding. Repeal would let non-utility companies, like Bechtel or Microsoft, acquire utility subsidiaries. It would also make it easier for non-US companies to do so. / *continued page 10*

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buyers prefer to own an interest in the power plant and to take a share of the electricity in kind (rather than buy it). Thus, developers have been driven to structures where each of the municipal utilities and cooperatives owns an "undivided interest" in the power plant. Each then separately finances its part of the power plant. Coops and municipal utilities can usually borrow at lower rates than private developers.

The IRS ruling suggests that municipal utilities need to be part owners of the plant before construction starts.

GAS INTERTIES are out of favor with the IRS.

Owners of independent power plants must negotiate terms with local utilities to let them connect to the grid. Otherwise, they have no way to move their electricity to market.

The utility will make the independent generator pay the cost of the radial lines, circuit breakers, substation improvements and other parts of the "intertie" needed to connect the plant. The utility will insist on owning most of this equipment. Ordinarily, when a corporation receives cash or property from someone who is not a shareholder, it must report the value as income. However, the IRS has said in a series of rulings since 1988 that utilities do not have to report interconnection payments by independent generators in cases where the generator is not a *customer* of the utility.

That is why most independent generators are careful to make sure they sell the electricity from their plants to someone else before the electricity reaches the grid. Otherwise, they would be customers of the utility for "wheeling" — or moving — the electricity across the grid. In cases where the electricity is sold before it reaches the grid, the customer is the one who pays for wheeling.

The IRS has been more stingy with rulings on arrangements with gas utilities. For example, where a gas producer connects to an interstate pipeline, the same principles should apply. The gas pipeline / *continued page 11*

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MR. MARTIN: I was going to ask what change you would expect in the domestic power market if PUHCA is repealed, but it sounds like you would expect to see more utility acquisitions, at least in the short term?

MR. WENNER: More, but you cannot say more concentration. While PUHCA prevents utilities from owning scattered utility subsidiaries, a separate FERC market power test prevents utilities from acquiring other utilities in the same market, or at least other utilities that own power plants. If PUHCA is repealed, then a MidAmerican would be free to acquire a utility subsidiary in Maine or California, but it would still have to pass the market power test administered by FERC, and toughened by the proposed legislation, before it could acquire other utilities with generating plants in the same market or in the same market region where it is already operating.

MR. MARTIN: What would PUHCA repeal mean for independent generators?

MR. WEISGALL: PUHCA repeal would bring a huge amount of new investment into the marketplace. I am guessing that would be a help. We do not have a completely competitive electricity market today because of the barrier to entry that PUHCA creates.

MR. MARTIN: Okay, another question: we talked earlier about the view of this panel that any energy bill that is enacted will probably repeal the part of the Public Utility Regulatory Policies Act that requires utilities to buy electricity from independent generators. How would existing independent power projects be affected? I am thinking of a project with an existing contract to sell its electricity to a utility.

MR. WENNER: The repeal provision, as currently written, would only apply in regions where the Federal Energy Regulatory Commission finds there is a competitive wholesale power market. Therefore, for a project in a part of the country where there is not such a market, the mandatory purchase obligation would remain. Even in places where there is a competitive market, existing contracts would not be affected. Such contracts would be grandfathered, but what would happen is that at the end of the term, the independent generator could not demand a new such arrangement.

Environmental Outlook

MR. MARTIN: Let me shift gears and ask Roy Belden in New York a question. President Bush has a "clear skies" initiative. It is a legislative proposal that would require further reductions in air emissions from power plants. I believe it covers mercury, nitrogen oxide and sulfur dioxide. Can such a bill pass a Republican-dominated Congress?

MR. BELDEN: The bill will face an uphill battle in the next Congress, notwithstanding the larger Republican majorities. The Senate Democrats blocked the proposal in the last Congress, and it never made any progress in the House.

MR. MARTIN: The Senate Democrats wanted tougher restrictions?

MR. BELDEN: That's right. The ranking member on the Senate Environment and Public Works Committee is Senator James Jeffords (I-Vermont), and he leads a faction that wants much steeper cuts in mercury, nitrogen oxide, and sulfur dioxide as well as carbon dioxide. The Democrats would like to see a four-pollutant bill. The Bush administration is strongly opposed to bringing in carbon dioxide reductions; it wants a three-pollutant bill. The Senate Environment and Public Works Committee will probably have a 10-to-eight split in the next Congress in favor of the Republicans, but you have one Republican Senator, Senator Lincoln Chafee from Rhode Island, who often sides with the Democrats on environmental matters.

Bush has made simplifying the US tax code a central theme of his second term. There is considerable skepticism about whether tax reform will occur.

That would make the vote even. The Bush plan faces a better chance in the full Senate if it can make it out of committee.

MR. MARTIN: You made the point to me earlier that it doesn't matter whether the Bush clear skies bill clears Congress. The Environmental Protection Agency is moving ahead with a plan of its own to restrict air emissions. What does the EPA action mean for power companies, and by when must they take action?

MR. BELDEN: The Bush administration is pursuing a parallel track. The Environmental Protection Agency has proposed a clean air interstate rule that would require reductions in sulfur dioxide and nitrogen oxide emissions. The rule is expected to go final later this year. The targets in it are similar to the targets in the clear skies bill that the President sent Congress. However, one significant difference is that the clean air interstate rule applies to 29 states — basically in the East, Midwest and South — while the clear skies act, if it is ever enacted, would apply nationwide.

MR. MARTIN: So power plants in 29 states will have to take action under the new EPA rule?

MR. BELDEN: Right. The clean air interstate rule adopts a two-phased approach. There will be emission reduction targets for sulfur dioxide and nitrogen oxide that must be met by the end of the first phase in 2010. The second phase targets must be met by 2015. Ultimately, you end up with reductions on the order of about 70% from current sulfur dioxide emission levels and about 65% for nitrogen oxide emissions.

MR. MARTIN: Will owners of even the newest power plants have to take action to reduce emissions from them, or are the targets a concern only for older utility plants?

MR. BELDEN: The greatest impact will be on older plants, and particularly older plants that do not have some of the current state-of-the-art technology for pollution control. Newer plants with state-of-the-art controls are less likely to be affected.

The other measure that I wanted to mention is the clean air mercury rule that the Environmental Protection Agency proposed. EPA proposed two alternatives for reducing mercury emissions. The favored approach is a cap-and-trade approach, where there would be a 34-ton mercury emission cap that would start in 2010, and then a 15-ton cap that would take effect in 2018. So ultimately, you end up with mercury reductions on the order of about 70%. / continued page 12

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company should not have to report the value of a gas lateral paid for by the producer to connect to the pipeline as long as the producer is not a customer of the utility for gas, storage or transportation.

However, IRS officials in Washington who write rulings in this area appear loathe to extend the same principles in the electric rulings to gas interties — at least not in cases that are different from what they have already analyzed in the electric area.

The IRS told a gas distribution company in a private ruling that it had to include intertie payments in its taxable income. The ruling is PLR 200448008. The agency made it public in late November.

The gas distribution company in the ruling received requests from local residents who wanted gas connections. For example, home builders would ask for extensions for new housing developments. The utility would do a cost-benefit study. If the potential return did not justify the investment, then it would ask the person requesting the extension to pay enough of the cost to make the investment economic.

The utility was also able to tap a "universal service fund" funded mainly by a rate surcharge for some of the money.

The utility asked for a ruling that it did not have to include in its income the cost reimbursements from the universal service fund or from homebuilders and others asking for gas extensions. The IRS refused. It said the amounts were income.

The utility argued that the payments were not from customers because the utility does not sell any gas — it merely transports it — and all the transportation charges are paid by the suppliers and not the end users of the gas. The IRS rejected the argument. It said the persons asking for line extensions were getting a customer-like benefit since they were setting themselves up for gas service.

The ruling reflects the / continued page 13

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Various Fuels

MR. MARTIN: I have been trying until this point to group the questions from the audience by topic. Now let me switch to asking questions in no particular order. One person asks, "What effect would repeal of the PURPA purchase requirement have on the economics of waste energy plants?" Adam Wenner, that is a good question for you.

Any significant overhaul of the US tax system could reduce the value of tax subsidies for investing in energy projects.

MR. WENNER: Most independent generators are not relying today on PURPA rights to sell the electricity from new plants. There are a few exceptions in the wind market. Most power from new plants is being sold into the grid or in a market where the price on offer is the same avoided-cost rate that one would get under PURPA. The same price is available whether one uses PURPA or not.

MR. MARTIN: Is there something about waste energy projects that makes them different in that respect?

MR. WENNER: Not that I can see.

MR. PETERS: Can I jump in here on waste energy and make two points?

One is that the PURPA contracts held by a number of waste energy projects are about to expire. The independent generators are trying to renegotiate them. They have an interesting advantage over other generators because they are willing to sign long-term fixed-price contracts that are indexed to something other than natural gas or oil because their fuel is not linked to either of the two. That is an advantage in the current market where you have very high natural gas prices and uncertainty about the price of oil. The other point is that the corporate tax bill that Bush signed in late October provides a tax subsidy for waste energy projects. They will qualify for a production tax credit similar to what wind developers get.

MR. MARTIN: The next question is, "What is on the horizon to help the development of IGCC in the way of tax credits, and are any members of the House or Senate supporters of IGCC?" The acronym "IGCC" stands for integrated gasification combined cycle. It is a combined-cycle power plant that uses coal gasification.

There were three tax credits for clean coal technology projects in the energy bill that failed to pass the current Congress. Some energy tax incentives were folded into a corporate tax bill that President Bush signed on October 22. The clean coal technology credits were not included. The future of those tax credits depends on whether there is an energy bill next year and, if so, whether the bill will have a tax title. If the answer to both questions is yes, then the clean coal credits probably have a fairly good chance of being enacted.

Gene Peters or Jon Weisgall, does either of you want to speak to what members of the House or Senate are the main backers for IGCC?

MR. PETERS: Jon, IGCC sits under the umbrella of clean coal technologies. Do you know who has been leading the charge?

MR. WEISGALL: I don't. However, it is worth noting that the corporate tax bill allowed production tax credits of $4.375 a ton to be claimed on the output from refined coal projects in the future. Developers of such projects were given until December 2008 to put them in service.

Renewables

MR. MARTIN: The next question is, "What is the likely Bush administration position on renewable portfolio standards, and what will happen at the state level?" Jon Weisgall?

MR. WEISGALL: Let's talk about federal and then state. First, there is interplay between a renewable portfolio standard, or RPS, and the production tax credit, or PTC. Speaking broadly, an RPS is a mandate. The PTC is an incentive. One is a stick and the other is a carrot. I would go so far as to say that an RPS without a PTC does not work, as we have seen in Nevada among other places. A PTC, without an RPS, is fine. If you can get a production tax credit that can get you to a market price, then you will have buyers for your output and you can compete with coal, nuclear and natural gas. The Bush administration opposes an RPS. Senator Bingaman had a federal RPS at 10% as one of the centerpieces of his bill.

The likelihood of a federal RPS being enacted by the next Congress is low. The topic is virtually off the table. Meanwhile, the states are implementing their own RPS standards without waiting for the federal government to act. Voters in Colorado passed a 10% RPS on November 2. Maryland now has one. Eighteen states have an RPS. Some of them, like the one in California, set the bar higher than any proposed federal standard. Texas is doing a good job. Iowa has done a good job with a rather crude RPS where the governor said simply, "Let's do some renewables," and I am proud that our company stepped in and said, "Here they are."

MR. MARTIN: Gene Peters, do you foresee a federal RPS in the next two years?

MR. PETERS: No. Some of our members are very much in favor of such a standard, but there is no support for it from the Bush administration and outright hostility to it in the House.

MR. WEISGALL: Let me ask Gene a question. What about a tradeoff where supporters of a cap on carbon dioxide emissions give up in exchange for a federal RPS?

MR. PETERS: I don't see the House seeing that as a "trade." Neither idea can make it through the House.

MR. MARTIN: The next question probably has a short answer, but it is a long question. Reading from an email: " A number of existing energy plants with PURPA contracts will be coming to the end of their contracts. Many smaller facilities — both cogeneration and small power — are uneconomic when compared to today's large combined-cycle gas and coal plants. Do you see any initiatives at the federal or state level to help preserve these facilities by providing special power contracts or contract extensions?"

MR. PETERS: I know of a number of smaller facilities — for example, biomass plants in California / continued page 14

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reluctance by the IRS branch that deals with these issues to extend the principles in the electric rulings to gas cases. Walter Woo, the IRS official who reviews rulings in this area, is retiring at year end.

CALIFORNIA will continue to assess 44 independent power plants at the state level.

An appeals court on November 30 rejected an effort to have the plant value determined by local assessors. The ruling means high property taxes for some independent power producers.

California, like other states, collects annual property taxes. The taxes are a percentage of the assessed value. Most property is assigned a value by county assessors, but property belonging to public utilities has historically been valued by the State Board of Equalization. Local assessors are barred by Proposition 13 from claiming more than a 2%-a-year increase in property value unless the property is sold. This limit does not apply at the state level.

California moved in late 2001, in the wake of charges that merchant power companies were gaming the system to boost electricity prices, to assess independent power plants at the state level. Some power plants that are "qualifying facilities" under the Public Utility Regulatory Policies Act and power plants with nameplate capacities of less than 50 megawatts are exempted from the change and continue to be assessed locally.

Independent generators assumed the move would lead to higher property taxes. It may have at least in some cases. Calpine is challenging a $320 million assessment for its Sutter Energy Center plant. The company believes the plant is worth only $243 million.

The state constitution directs that property belonging to any "regulated . . . companies transmitting or selling gas or electricity" should be assessed at the state level. The independent generators maintain that independent power / continued page 15

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— that have already had to shut down. I do not see any federal intervention to keep these plants operating. It is possible that some states might see an advantage in helping plants that assist with waste disposal continue to operate — for example, Florida does not have as many options for disposing of waste as do states in other parts of the country — but I don't know.

The Environmental Protection Agency is moving ahead with plans to require up to 70% reductions in emissions from power plants in 29 states.

MR. WENNER: Gene, in some states, the renewable portfolio legislation or a predecessor statute establishes, in effect, a subsidy from a state-collected trust fund that can supplement payments to projects that qualify as renewables.

MR. PETERS: That is absolutely true, but those programs are directed at renewables rather than small power plants.

MR. WENNER: For instance, I believe Maine defined renewables for purposes of the state RPS program as everything that qualifies under PURPA.

MR. WEISGALL: I think we all agree that there will not be any federal intervention. There may be isolated instances where states take action with a public goods charge or the like, and if the price of natural gas keeps climbing, then maybe biomass plants will remain on line for purely market reasons.

MR. MARTIN: A standard market design question — will the tentative steps that FERC has taken toward standard market design, or opening the grid to competition, be reversed by the next Congress?

MR. PETERS: What is the baseline for comparison? The SMD proposal is gone. We no longer use that acronym. FERC has decided to adopt a regional approach. You have a strong effort to get an independent system operator functioning in the Midwest.

Do I see a lot of pushback from Congress on some of these initiatives? You will see some at the edges. Some members of Congress from the West have concerns about cost. Municipal utilities and electric cooperatives have been pushing back and generating letters from members of Congress. FERC has responded to some of the pressure.

Do I see a sharp reversal of FERC policy under pressure from Congress? I don't at this point, mainly because I think the FERC policy is already fairly accommodating to state and local interests. The opponents of the FERC policy have already gotten a lot of what they wanted. That is not to say there are no longer any issues. The new market power test is getting pushback from some of the southeastern utilities. They are exerting a lot of pressure on FERC. The pressure could have an impact.

MR. MARTIN: We have only a few minutes remaining. Let's see how many of the remaining questions we can put to the panel. Does anyone see the Federal Energy Regulatory Commission taking "significant steps to insure that the southeastern regional market moves to create a more level playing field for independent generators?"

MR. PETERS: What Southern Company and Entergy opposition to the new market power test will do is make it difficult for them to have market-based rates. That will put pressure on them, in turn, to broaden the market and lead to development of a regional transmission organization. I am not saying this is certain to happen, but I can see things moving in that direction.

MR. WEISGALL: I will give a one-word answer: no.

MR. MARTIN: Next question — "Is there any possibility of changing the federal tax incentive system for renewables in order to make it more market driven and competitive, rather than the usual annual push for an extension of the production tax credit in its current form?"

MR. WEISGALL: The production tax credit has now been expanded so that it no longer applies solely to wind and closed-loop biomass, but it now also covers other renewables, including open-loop biomass, geothermal, solar and landfill gas. The problem is that projects must be put into service by December 2005 to qualify. That does not leave enough time for a geothermal project to be built. It does not leave enough time for biomass projects. It really only works for wind farms.

What the industry needs is for the date to be extended by another three to four years at a minimum.

Maybe you trade a longer time period to build new projects for a shorter duration for the credits — for example, projects would have until the end of 2008 to be completed, but tax credits could be claimed on the electricity output for four or six years rather than 10 years. Alternatively, maybe the amount of the credit would be less than 1.8¢ a kilowatt hour. The problem is the cost. The reason the credit is extended for short periods at a time is the Congressional scoring. The budgetary impact of a three-, four- or five-year extension is much greater. You end up with five one-year extensions and they are not the same thing as one five-year extension because the industry is driven to boom and bust. ◎

Current Merchant Plant Prices

by Jeff Bodington, with Bodington & Company in San Francisco

Sales of merchant power plants have more than quadrupled so far in 2004. The backlog of merchant plants for sale is being worked down, and buyers and sellers are closing the spreads that led to much talk but few actual sales. Some participants have questioned whether or not the very low price Duke received for its portfolio of merchant plants in the southeastern United States is a benchmark for pricing other merchant plants that are still on the market.

This article summarizes the merchant sales activity and puts the Duke deal into perspective.

In brief, while the Duke sale now stands with sales of the PG&E National Energy Group portfolio for low value, none of these sales should set a mark for the value of all merchants.

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companies are not regulated utilities in the sense envisaged by this phrase in the constitution. The appeals court disagreed. There is concern that because the court suggested that independent power plants are like public utilities, this could open the door to broader regulation of such plants. The court said the companies owning the plants are public utilities in the sense that they supply their output indirectly to the public and benefit in many cases from use of public funds and purchase commitments from the state government.

The Independent Energy Producers Association is deciding whether to appeal to the state Supreme Court.

A 'CLAIM OF RIGHT" led to a tax refund.

Quaker State Corporation bought oil from smaller, independent oil producers in Pennsylvania, but was later accused in a class-action lawsuit filed against it and other oil companies of conspiring to keep oil prices low. It settled the price-fixing suit for $4.4 million.

Quaker State paid taxes each year during the 14-year period at issue in the lawsuit using "inventory accounting," meaning that it matched its costs each year to the oil it sold that year to calculate its taxable profit. It made payments to settle the lawsuit in 1995 and 1996. By then, tax rates were lower than they had been for part of the period during which it was accused of engaging in price fixing. Had it originally paid the independent producers the full amount for their oil that the settlement suggested it should have paid, then it would have had less income to report during the 14-year period. Because tax rates were higher then, deductions for the extra costs would have been more valuable if taken at the time rather than in 1995 and 1996 when the settlement was paid.

The company made a "claim of right" under section 1341 of the US tax code. That section allows a company that, with the benefit of hindsight, can see it overre- */ continued page 17*

Merchant Plants

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Recent Sales

More than 18 transactions involving more than 100 merchant power projects are now pending or have closed. Net installed capacity sold totals over 14,350 megawatts. Reliant's sale of the Orion portfolio to Brascan included 72 hydroelectric projects and, without this transaction, the total merchant sales to date would be 30 projects with an aggregate net capacity of approximately 14,000 megawatts.

The average price paid for gas-fired merchant power plants that have sold to date is about $225 a kilowatt.

Nearly all of these are natural gas-fired combustion turbine-based projects constructed when the merchant business model appeared to thrive. These sales include 30% to 50% of the total merchant capacity built during the last five years. While the merchant sector is far from sold off or abandoned, these sales show that substantial progress has been made.

Sellers are primarily the developers and lenders who invested heavily in merchant generation. Developers are responding to pressure from Wall Street to repair their balance sheets. Lenders are responding to pressure from both Wall Street and the federal Office of the Comptroller of Currency, or "OCC." In at least a few cases, the OCC is forcing writedowns that make sales a less-painful alternative. Buyers are diverse; utilities, independent power companies and private equity funds. Utilities of various types account for most of the transactions. Investor-owned utilities, municipal utilities and other entities whose ratepayers will be at risk if the new owners cannot make a go of the plants account for more than 70% of the sales by number of transactions, 45% of the sales by generating capacity and 50% by the value exchanged. Among independent power companies, Calpine has been both a buyer and seller.

Private equity firms have spent much time looking at merchant acquisitions; however, few have become buyers. The Duke sale of its merchant portfolio in the southeastern US is an example of an unusual closing. Most private equity buyers have been more successful in pursing generation that involves less risk than merchant operations: either regulated utilities or non-merchant independent power. Texas Pacific Group formed Oregon Electric Utility Company to pursue acquiring Portland General Electric from Enron. Kohlberg Kravis Roberts & Company, Blackstone Group, Texas Pacific Group and Hellman & Friedman have joined to purchase the former Reliant unit Texas Genco. AIG, Algonquin Power, Arclight Capital Partners, Goldman Sachs, Harbert and many others pursue projects whose revenues are secured by long-term contracts.

Focusing on Duke, Duke Energy North America developed numerous merchant projects and had a portfolio of eight projects in four states located within an area of the United States called the "Southeast Electric Reliability Council," or "SERC." All eight plants are natural gas-fired and most of their 5,280-megawatt combined capacity went into service during 2002. As Duke's heavy investment in merchant generation failed to yield current earnings, asset sales began. Lackluster bids forced Duke to write down the value of the plants three times, and the portfolio was ultimately sold to KGen Partners. KGen is owned by MatlinPatterson, a firm that focuses on distressed debt and that was founded by distressed-debt specialists David Matlin, Mark Patterson and Lap Chan. The three founders were with Credit Suisse First Boston. Their first fund was $2.2 billion, and the second recently limited funding at $1.66 billion. The firm has invested in WorldCom/MCI, Huntsman, Oxford Automotive and now electric power by buying debt of NRG Energy and purchasing the Duke projects.

Value of Duke Southeast

Merchant sales have been painful experiences for sellers.

While $/kW is a very rough guide to value, the range of prices is approximately $90/kW to $790/kW. The average for gas-fired projects is approximately $225/kW. High-value projects tend to be combined-cycle facilities with relatively low heat rates purchased by ratepayer-at-risk entities. Purchases by Avista, GenTex, Puget Sound Energy and the City of Brownsville are examples. Low-value projects tend to be combustion turbine peakers with heat rates over 11,000 Btu/kWh in regions such as SERC and ECAR (Delaware, Maryland, parts of Pennsylvania, West Virginia, Tennessee, Kentucky, Ohio, Indiana and Michigan) that have ample reserve margins and substantial coal and nuclear generation. The Duke GE 7EAs located in Georgia, Kentucky and Mississippi purchased by KGen are an example. Details of the Duke portfolio show more about why its value is not a benchmark for merchants in general.

Duke's southeastern merchant portfolio included three combined-cycle projects and five peakers. Combined-cycle projects accounted for 2,360 megawatts of the 5,280 megawatts in total. The results of a multiple-round auction were announced on May 4, 2004, and the acquisition with KGen closed four months later on August 5.

The transaction had three key components: cash, a high-yield note and a power purchase agreement. Total cash was $425 million. Regarding the high-yield note, Duke holds a $50 million receivable from KGen. This note bears interest at LIBOR plus 14.5% and is secured by a fourth lien on KGen's owner. Interest compounds quarterly, and both interest and principal are due in a balloon payment after 7.5 years. The transaction included a seven-year power sales agreement between KGen and Georgia Power for output from one of the plants: the Murray combined-cycle facility. Duke operates this project under a long-term operations and maintenance agreement. As part of this agreement, Duke arranged a $120 million letter of credit to secure the obligations of KGen to Georgia Power, and KGen has an obligation to reimburse Duke for LC-related expenses and drawings. While these details show that the transaction was more complex than the often-quoted figure of $475 million, they also show that there may be additional value to each party embedded in terms of the transaction. The high rate on the note may add value for Duke. The LC obligation impairs Duke's balance sheet, and the arrangements concerning Murray have benefits and costs for both parties.

The economic logic of the price lies in / continued page 18

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ported its income in an earlier year to get the benefit in its current tax year of an adjustment that takes into account the change in tax rates. Quaker State could simply have deducted the settlement payments 1995 and 1996. However, the deductions were inadequate recompense because they were against a lower tax rate.

Quaker State initially filed tax returns for 1995 and 1996 on which it simply deducted the settlement payments. However, it later realized that it was entitled to a larger tax adjustment and filed amended returns claiming another $375,000 in tax reductions. The government objected. The federal Claims Court held for Quaker State in a decision in late October. The case is *Pennzoil-Quaker State Co. v. United States*.

A FOREIGN TAX CREDIT STRATEGY that the IRS dislikes is proliferating.

The United States taxes US companies on their foreign earnings, but it allows a credit to be claimed for any income taxes that were already paid abroad on the earnings.

There are two kinds of foreign tax credits. One is credits for taxes that the US company paid directly. The other is "indirect" credits for taxes that an overseas subsidiary paid. For example, when an offshore subsidiary earns income, pays taxes to another country, and then distributes the earnings to its US parent as a dividend, the US parent can claim credit for the income taxes already paid by its subsidiary. This is called an "indirect" credit because the US parent did not pay the taxes itself.

One foreign tax planning strategy involves freeing up foreign tax credits to be claimed in the United States while the earnings remain parked in an offshore holding company.

The IRS is fighting one such structure used by Guardian Industries, a US insurance company, in court. Guardian had a group of Luxembourg subsidiares. There was a holding company in Luxembourg. The other subsidiaries were under the holding company. / continued page 19

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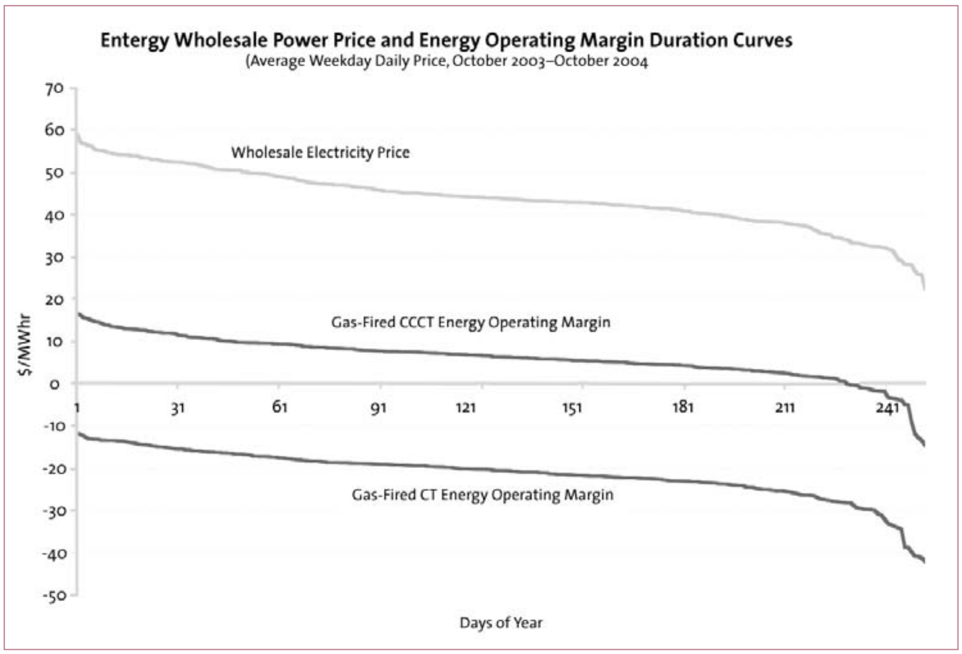
both the characteristics of the projects and the regional market for power. While the projects are new and efficient, it is the nature of the regional market for electricity that led to a relatively low price for the merchant assets. Key aspects of these factors appear in the graph below.



The top line in the graph shows the number of days during the last year on which the average daily wholesale electric power prices in the Entergy region of SERC exceeded the price on the left axis. The curve shows only weekdays; low weekend loads mean that merchants are usually idle when regional capacity margins are high. For example, this "price duration curve" shows that the price was at least \$20/MWh at all times and at least \$50/MWh for about 50 days of the year. The curve shows the potential gross revenue available to a merchant. Compared to many other regions, the graph shows that potential gross revenue in SERC is not substantial. Non-gas generation dominates supply, and much new capacity is under construction. Seventy five percent of the 182,000 megawatts in generating capacity available in SERC during 2004 is from coal, nuclear, hydro and pumped storage. Further, while the capacity margin reported on the Forms 411 filed with the federal Energy Information Agency is currently approximately 15%, the margin including projects with signed interconnection agreements is forecasted by SERC to exceed 30% through approximately 2010.

The top line in the graph addresses gross revenue. The bottom two lines address net revenue after fuel costs. This net, "energy operating margin" is what funds are available to cover non-fuel operating costs and then yield some capital value. The bottom two lines show that the three combined-cycle combustion turbine projects in the Duke portfolio could operate profitably about 230 days of the year. However, the peaking combustion turbines, due to their higher heat rates and thus fuel costs, could never make money on a daily average basis. Profitable operations on only a few high-load afternoons may be feasible. Future increases in SERC's increasing capacity reserve imply that near-term improvement in this situation is not likely.

The present value of the operating margin in the graph for the combined-cycle plants justifies a price of approximately \$50/kW for the entire 5,280-megawatt portfolio purchased by KGen. The actual price of approximately \$90/kW shows that the buyer expects some combination of the Murray contract, peak-hour operations for the combustion turbines, load growth in SERC and lower natural gas prices to add value. Holding these projects for response to future requests from regional utilities and adding steam cycles to some of the peakers are examples of additional potential sources of value. For other merchants in other regions, a similar calculation supports prices close to those at which projects actually trade.

In sum, this brief analysis shows that KGen did not make an obviously terrific buy, and what KGen paid does not mean that many other merchants are worth as little money as KGen paid. ◎

REC Market Update

by James Scarrow, in Washington

The number of states with programs to promote the development of renewable energy continues to grow, creating both new opportunities and complexities in the US power market.

Background

At last count, 18 US states had adopted renewable portfolio standards — called RPS — requiring electric utilities to supply a specified minimum percentage of their electricity from renewable fuels, such as wind, biomass and small-scale hydropower. At least three other states are debating whether to impose similar requirements.

Although each state RPS program is unique, each program addresses six core issues. They are what qualifies as a renewable, the goal, frequently expressed as a percentage of the state's total retail load, a phase-in schedule, the manner in which electricity retailers are allocated responsibility for achieving the goal, whether a utility that does not want to generate electricity from renewable fuels can satisfy its obligations by purchasing "renewable energy credits" from other, renewable generators, and the penalties for non-compliance and alternative methods for achieving compliance, such as making payments to a state's renewable energy trust fund.

Some states have tiered RPS programs in which certain types of renewable resources are valued more than others, or in which the program has specific goals for certain types of renewable resources, such as solar energy.

Of the 18 states with some form of RPS program, six adopted their programs within the past year. The six are New York, Maryland, Hawaii, Rhode Island, New Mexico and Colorado. In addition, the Pennsylvania legislature passed a bill in November that strengthens an existing RPS program in that state. The bill would require that 18% of the state's energy come from alternative resources by 2020. Governor Rendell was expected to sign the bill as the *NewsWire* went to press.

The Union of Concerned Scientists estimates that existing RPS standards will result in approximately 22,000 megawatts of new renewable energy being developed by 2017.

Renewable Energy Credits

Renewable energy credits — called RECs */ continued page 20*

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Luxembourg allows groups of related Luxembourg companies to file a single, consolidated tax return. Guardian elected to treat the holding company that sits atop the Luxembourg group as a "disregarded entity." That means the holding company does not exist for US tax purposes. It treated the companies immediately below it as corporations.

Guardian then took the position that all the taxes that had to be paid to Luxembourg on the group return were taxes of the Luxembourg holding company. This meant that credits for taxes paid to Luxembourg were direct credits: the holding company did not exist so any taxes paid by it are considered paid by the US parent directly. The IRS objected. It said the taxes should have been apportioned among the various companies in the Luxembourg group. The case is in the federal Claims Court in Washington.

Meanwhile, Australia moved in 2002 to let affiliated companies in that country file consolidated tax returns. All the companies joining in the return are ordinarily liable for the full amount shown on the group return, but they can alter this through tax sharing agreements that assign to the liability to just one member of the consolidated group. The rules let two Australian sister companies that have the same offshore parent join in a consolidated return, but shift all the tax liability to one of the companies through a tax sharing agreement. This opens the door to the same sort of tax planning in which Guardian Industries engaged. The United States is not happy with the Australian tax law changes.

The IRS has at least one other case like the Guardian situation pending. It involves another country.

The agency has a regulation in the works to prevent the stripping of foreign tax credits without the associated income through use of "check-the-box" elections (to treat offshore companies as transparent). */ continued page 21*

RECs

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— are a mechanism that can be used in some states to comply with the RPS requirements, and they are potentially an additional source of financing for independent generators in such states.

	State	Goal	Tradable RECs?
1	Arizona	1.1% by 2007	no
2	California	20% by 2017	no
3	Colorado	10% by 1015	planned
4	Connecticut	6% by 2009	yes
5	Hawaii	20% by 2020	no
6	Iowa	2% by 2000	no
7	Maine	30% by 2000	yes
8	Maryland	7.5% by 2019	yes
9	Massachusetts	4% by 2009	yes
10	Minnesota	19% by 2015	yes
11	Nevada	125% by 2013	yes
12	New Jersey	6.5% by 2008	yes
13	New Mexico	10% by 2011	yes
14	New York	24% by 2013	no
15	Pennsylvania	18% by 2020	planned
16	Rhode Island	16% by 2019	yes
17	Texas	2880 mW by 2009	yes
18	Wisconsin	2.2% by 2011	yes

Eleven states currently use, or are intending to phase in, REC trading programs. Under these programs, a generator of renewable electricity earns one credit for each megawatt hour of electricity that is generated. RECs can then be bought, sold or accumulated and used to achieve compliance in that same year or to meet future year compliance requirements. The rules for earning and transferring RECs vary from state to state, but the building blocks of a REC program are certification and distribution of the RECs by the administering authority to generators, a tracking system and a sunset date at which time the REC expires unless used.

Through state REC programs, the renewable attributes of energy are unbundled from the electricity commodity. This has several important implications. First, because RECs are credits rather than physical commodities, the transfer of a REC from a seller to a buyer does not occur over transmission lines but rather as an accounting entry. Second, renewable electricity generators can have two separate revenue streams in theory — one from the sale of commodity electricity and one from the sale of RECs — allowing generators to seek the maximum sales price for each individual stream. (In practice, various states have proceedings underway to decide who owns the RECs in cases where the electricity is sold by an independent generator to a utility. Utilities argue the RECs convey with the electricity.) Third, the market forces can be harnessed to help ensure that a state's RPS goals will be achieved in an economically efficient manner.

In order to ensure that an individual REC is not used more than once to meet RPS compliance requirements, it is necessary to have an REC tracking system. REC tracking systems give unique identification numbers to each unit of renewable energy generated, which allows the RECs to be tracked from generator to subsequent owners until the REC is used by a utility for compliance. There are three REC tracking systems currently in operation — one in Texas, one for the states in the New England power pool, and one in Wisconsin. Several other tracking systems are in the developmental stage.

The volume of REC purchases has been on the rise as states ratchet up the amount of electricity that must come from renewables. In 2003, there was more than a four-fold increase in REC sales as compared to 2004. The rising demand for RECs (primarily as a result of RPS programs) has kept REC prices higher than some had originally anticipated.

The price of RECs in the various state REC markets is a function of supply and demand. In Massachusetts, where the state has a relatively narrow definition of what qualifies as a renewable, there is currently a shortage of RECs. As a result, REC prices in Massachusetts are now bumping up against the program's alternative compliance payment price of $50 per megawatt — that is, the payment a utility can make into the state's renewable energy trust fund as an alternative method of achieving compliance. Other states with REC programs have seen rising or steady REC prices over recent months.

While owners of renewable energy facilities generally benefit from high REC prices, high prices can be a double-edged sword. Under REC purchase agreements and under general principles of contract law, a REC seller may be liable to a REC purchaser for the costs of obtaining replacement RECs at market prices if the seller is not able to provide the REC from the intended source. Depending on the market price of RECs, the cost of providing replacement RECs could be significant.

REC Ownership

Disputes have arisen over whether utilities that purchase electricity through long-term contracts are entitled to the RECs associated with that electricity where the power purchase contract is otherwise silent on the issue.

Under PURPA (the acronym for the Public Utility Regulatory Policies Act), utilities are required to buy power from two types of independent power plants at the "avoided cost" the utility would have to pay to generate the electricity itself. Most power purchase agreements between utilities and independent power producers were entered before enactment of state RPS programs and, therefore, do not address the question whether the purchaser is entitled to any RECs associated with the electricity being sold.

Representative REC Prices

State	REC Price
California	$38
Massachusetts	$49
New Jersey	$49
Texas	$12

Source: October 2004 REC market report of Evolution Markets LLC

In 2003, several independent power producers sought an order from the Federal Energy Regulatory Commission declaring that avoided-cost power sales agreements entered pursuant to PURPA do not inherently convey to the purchasing utilities any RECs. By order dated October 1, 2003, FERC ruled that RECs do not automatically convey to the utility and that the question whether RECs convey is a state-law issue. Even though FERC bounced the issue to the states, it emphasized — to the disappointment of electric utilities — that avoided cost rates in power purchase agreements under PURPA are only intended to compensate independent generators for electric capacity and energy and not for environmental or other attributes. In this regard, FERC noted that the avoided cost paid by a utility under a PURPA contract does not depend on whether the generating facility is a fossil-fuel-fired plant or a renewable energy generating facility. The logic of FERC's decision suggests that REC ownership should remain with the independent generator unless the RECs are expressly conveyed. Nevertheless, it remains unclear how individual states will decide the issue.

In Maine, the Public Utilities Commission determined that utilities / continued page 22

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DENMARK is considering making it harder to file group tax returns.

Danish holding companies are used by many US multinational corporations, although Holland and Luxembourg continue to be more popular because of their wide treaty networks that reduce taxes in other countries and for other reasons.

Denmark has allowed Danish holding or parent companies to file group returns with their foreign and local subsidiaries since 1903. The holding company is free to choose which subsidiaries it wants to include on the group return. Starting in 2004, it has also been possible for two Danish subsidiaries of a common parent company elsewhere in the European Union to join together in filing a group return.

The government is concerned about the revenue loss. Parent companies choose to include subsidiaries that have losses and exclude those with profits. The tax minister said in late November that the government would ask parliament to tighten the rules.

In the future, either all eligible subsidiaries — both foreign and domestic — would have to be included or none would be. An election would be binding for 10 years. Any subsidiaries in which the holding company owns more than 50% of the shares would have to be included in the event of an election. Under current rules, a subsidiary can be included only if the parent owns all the shares (or, for subsidiaries outside Denmark, all the shares that it is allowed to own under local law).

The government is expected to ask at the same time to reduce the corporate tax rate from 30 to 28%.

TELEPHONE COMPANIES won a victory.

A US district court in New York said that a 3% federal excise tax that the US government collects on telephone calls does not have to be collected on charges for long-distance calls, unless the charges vary by the distance of the call. In the case before the / continued page 23

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purchasing power from independent generators also get the RECs in cases where the power purchase agreement is silent on the matter. Utilities that cannot obtain clear title to RECs from independent generators under contract can achieve RPS compliance by submitting evidence of contractual entitlement to the electric power from renewable power plants. As a consequence, certain RECs will, in effect, be double counted towards the achievement of Maine's RPS goal.

Prices for renewable energy credits range from $12 to $49 a megawatt hour depending on the market.

The New Jersey Board of Public Utilities has not yet determined whether wholesale power contracts automatically transfer REC ownership, but it ruled that for the initial two years of the state RPS program, utilities would be credited as if REC ownership were conveyed with electricity under power sales agreements. In August 2004, the New Jersey Board of Public Utilities invited public comment on the question of REC ownership. As would be expected, utilities and ratepayer advocates have taken the position that RECs should belong to the utility, and that any other result would be a windfall to independent generators. Independent generators claim the utilities would receive a windfall if they have their way.

According to Anna Giovinetto, director of renewable energy markets for Evolution Markets LLC, because of the cloud of uncertainty surrounding the question of REC ownership, many RECs that might otherwise be available to be bought and sold are not on the market. This has contributed to REC shortages in states such as Massachusetts. It may be many years before the REC ownership issues are resolved in the states with REC programs.

Source of Finance

REC purchase agreements hold out the possibility of providing a second potential revenue stream for renewable energy projects. However, to date, creditworthy REC purchasers have been reluctant to enter into REC purchase agreements for terms longer than five years. As a result, the revenue streams from REC sales have generally not been able to support long-term financings, which can have 10- to 15-year terms.

One of the reasons that long-term REC purchase agreements have been rare is because of the way electricity markets have been restructured. In New Jersey, for example, electricity distribution companies bid out their basic generation services through an auction process. Through this process, the winning bidder will provide generation services — including compliance with New Jersey RPS requirements — for a specified portion of the overall load and typically for a period not exceeding three years. Because the winning bidders provide those services for a relatively short period, they are unlikely to enter into long-term REC purchase agreements.

A number of states have taken steps to facilitate long-term REC purchase agreements the revenues from which can support project financing. Such steps range from requiring utilities to enter into long-term REC purchase agreements to direct purchases of RECs by state entities. In the recently-adopted Colorado RPS, utilities are required to enter into 20-year contracts for the purchase of renewable energy. The California RPS program requires investor-owned utilities to solicit bids for 10-year contracts for renewables, while utilities in Connecticut have until 2007 to enter into longer than 10-year contracts totaling at least 100 megawatts with projects supported by the state's Renewable Energy Investment Fund.

Massachusetts takes a different approach to fostering long-term REC purchase agreements. The Massachusetts Technology Collaborative, known as the MTC, enters into long-term REC purchase agreements with selected renewable projects. (The MTC receives funds to purchase RECs from that state's systems benefits charge established as part of the Massachusetts electricity restructuring law.) These agreements either provide for the direct purchase of RECs by MTC or give the seller the option to sell RECs to MTC at a specified price on a future date. The first set of such support contracts was entered by MTC in 2003. The MTC hopes to sell its positions in REC purchase agreements and, at current prices, will probably be able to do so at a profit.

In New York, the New York Public Utility Commission issued an order on September 24, 2004 adopting an RPS goal that renewable electricity must amount to 25% of the state's electricity supply by 2013. The New York RPS program will be funded by delivery charges to be imposed on electric utility customers beginning in the fourth quarter of 2005. These charges will be used by the administering body, the New York State Energy Research and Development Authority (or NYSERDA), to enter into direct long-term purchase agreements for renewable energy. Unlike in Massachusetts where the MTC enters long-term REC purchases as part of a market-based RPS program, in New York, NYSERDA will be the central purchaser of renewable energy and there will be no REC program. The staff of the New York Public Utility Commission is still working on the implementation plan for the New York RPS program. It is expected to be released for public comment in the first half of 2005.

Time will tell which approach to encouraging long-term REC purchase agreements is most effective.

Cross-Boundary Transactions

There is currently an interstate market for RECs among the six states that comprise the New England power pool, or NEPOOL — Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. Of these six states, four — Connecticut, Maine, Massachusetts and Rhode Island — have RPS programs that allow utilities to satisfy their RPS requirements by purchasing RECs from generators anywhere within NEPOOL, including generators located in New Hampshire and Vermont, which do not have RPS programs. The buying and selling of RECs within NEPOOL is administered by the NEPOOL generation information system.

RECs from one NEPOOL state can be only be used to satisfy the RPS requirements in another NEPOOL state if the characteristics of the REC satisfy the requirements of the particular state RPS program where the REC will be used. This can result in a variety of complicated */ continued page 24*

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court, the telephone customer was billed based only on the duration of his calls and not also the distance.

Critics of the telephone tax complain that the law is antiquated and needs to be rewritten by Congress. The US government collects a 3% excise tax on "communication services," which are defined as "local telephone service, toll telephone service and teletypewriter exchange service."

Long-distance calls may be taxed as "toll telephone service" depending on how the customers are charged. They are taxable if customers are charged fees that vary "with the distance and elapsed transmission time" of each call and the fees are "paid within the United States." Alternatively, the calls are taxable if the service is like a WATS line where the customer can make an unlimited number of calls outside his local phone system for a flat fee or for fees tied solely to the amount of time spent on the phone.

The New York case is *Fortis, Inc. v. United States*. The court gave the litigants its decision in mid-September, but the decision was not released to the public until late October.

The government argued in the case that it should be able to collect taxes on long-distance calls even if the customers are billed based solely on the duration of the calls. The court declined to read the word "distance" out of the statute. It also rejected the government's claim that the call charges in the Fortis case varied by distance because the phone company had different rates for intrastate, interstate and international calls.

Two other US courts split in similar cases earlier this year. A US district court in Florida ordered the phone company to collect taxes in a case called American Bankers Insurance Group v. United States. *A US district court in Ohio said in* OfficeMax v. United States *that charges must vary both by distance and elapsed time to be taxable.*

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compliance scenarios because each state's RPS has its own particular eligibility requirements. For example, projects in Connecticut may not qualify as a renewable under the Connecticut RPS program but they might meet the Massachusetts requirements. Conversely, a project in Massachusetts might qualify as a renewable resource in Connecticut, but not Massachusetts.

As RPS programs continue to spread and existing REC markets mature, the complexities can be expected to multiply. ◎

Risk Allocation in Wind Projects

by Paul Weber, in New York

The developer of a windpower project must contend with many risks that may not affect a more conventional power plant. These risks range from fickle winds that blow in different ways at varying times and places, to a fickle Federal government that approves for only limited time periods the production tax credit (currently 1.8¢ per kilowatt-hour) that accounts for a significant portion of the value in the project, leading to boom and bust cycles in wind farm development.

As is the case with more conventional power plants, a fairly well-developed risk-allocation regime has evolved for windpower projects that follows the project finance maxim of allocating risks to the persons best able to manage them. This article examines some of the key risks and how they are handled.

Wind Risk

Wind is the "fuel" that powers wind farms and like any power project, assuring a reliable fuel supply is essential to developing a viable wind farm. Power purchase agreements for wind farms typically provide for energy-based payments — when the wind blows, electricity is produced and the developer makes money; when the winds are silent, the developer does not. Production tax credits work essentially the same way. In addition, under some power purchase agreements, the offtaker will pay a lower price for energy delivered if the windpower project does not produce enough energy to meet specified targeted amounts. Even a small shortfall in actual wind over a sustained period relative to forecast wind may, from an equity investor's perspective, make the difference between a good investment and a bad one. Thus, the challenge is to obtain a site for the wind farm where the developer has a high level of comfort that the wind resource is as good, and as well forecast, as possible.

This determination is made by the wind consultant for the project using site-specific and regional data and studies. Wind is a variable resource. It varies by season and by time of day. It also varies from year to year. At a specific wind farm site, it can also vary at different heights and as a result of different terrain and vegetation. Thus, it is essential that the wind consultant collect data that reflects the conditions that the wind turbines can be expected to experience at their various locations on the site. In general, the more data and the higher its quality, the better the accuracy of the forecasts derived from that data. Data collection should be closely monitored to assure that quality is maintained throughout the data collection process. The goal is to obtain recorded consistent trouble-free data from each collection tower and at each tower height where data is collected. Wind resource consultants say the best data is long-term (at least one year and preferably two) and site specific.

The wind consultant collects all this data and uses various analysis techniques and computer models to create a series of probabilistic cases for wind power production (based upon forecast wind and wind farm power curve data) at the relevant site. These cases are likely to reflect 50%, 75%, 90% and 95% confidence levels for one- and 10-year probability forecasts. They may also include a P99 case, which represents a 99% confidence level. Wind data and analysis are also used by wind consultants to advise developers on the optimal siting of each wind turbine at the site and the most suitable turbine to use. Developers may also use wind forecasting to schedule maintenance during periods of anticipated lower wind speeds. Wind forecasts can also be a useful tool in scheduling and dispatching wind farm output.

Lenders to wind projects generally require, as a condition to closing, that a developer provide a wind consultant's and independent engineer's report reflecting a range of confidence levels (generally from 50% to 95%) for one- and 10-

year probability forecasts. These numbers are plugged into the financial model for the project to determine the projected debt service coverage ratios over the range of confidence levels. Lenders address wind resource risk by typically looking for a minimum debt service coverage ratio of 1.50:1.00 over the life of the loan based upon the P50 case and a minimum ratio of 1.00:1.00 for a P90 or P95 case. In certain instances, lenders have also required developers to demonstrate that the loan can be serviced in any year under a P99 case using a portion of the debt reserve fund.

Wind risk may also be addressed through derivative products. Though not in wide use, wind hedges may be purchased that will protect a developer against low and excessively high wind conditions. Wind hedges are created on a formulaic basis to address wind risk. The formula includes fixed assumptions as to price and the power curve, among other things, with wind speeds as the variable input. The hedge provider is obligated to make payments based upon the formula in the event wind speeds are below or above agreed levels. Of course, wind hedges cost money so that, by purchasing a wind hedge, a developer is essentially reducing its upside while protecting against a downside case.

Transmission Risks

Transmission risk, and especially curtailment risk (the risk that in certain periods demand for transmission may outstrip supply, resulting in reduced or no transmission service during these periods), is a very significant issue in any windpower project. This is because wind is an intermittent resource that may render the purchase of firm transmission capacity for a windpower project uneconomic. The nature of this risk, and thus how it is addressed, is largely defined by the transmission rules for the transmission system over which the windpower project transmits its energy. (For a discussion of some of these rules, see "Federal Regulatory Issues in Windpower Projects" in the October 2004 *NewsWire*.)

The optimal means for a developer to address curtailment risk is to persuade the offtaker to accept this risk under the power purchase agreement. A simple means of achieving this result is to provide for an electricity delivery point at or near the wind farm site. However, this issue can be very contentious and developers are not always successful in laying off curtailment risk. This may / *continued page 26*

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MEXICO will not allow Mexican companies to deduct interest paid on debt if the companies are too "thinly capitalized."

This was one of a series of tax law changes that the Mexican Congress passed on November 13. They are expected to take effect on January 1.

"For the first time, the income tax law will include a limitation on the deduction of interest due on debt based on adequate capital levels," José Ibarra with the law firm Chevez, Ruiz, Zamarripa y Cia reported from Mexico City. Companies will not be allowed to deduct interest paid on "excess" debt — that is debt exceeding a 3-to-1 debt-equity ratio. Only loans from related parties or from foreign lenders are taken into account. However, there are still other uncertainties about how to calculate debt, according to Ibarra.

The law has a transition rule for companies that already exceed the permitted ratio. They have five years to comply, but must reduce their debts each year in "equal proportionate parts." Ibarra said that companies that have trouble complying may be able to avoid the restrictions by entering into advanced pricing agreements with the Mexican tax authorities. Financial institutions are exempted from the new limits, but the exemption may be subject to constitutional challenge.

The new law also limits deductions for amounts paid to companies in tax havens. Mexico has had a tax havens list in the past. The list this year has almost 100 jurisdictions on it. However, starting in January, the list will be replaced with a general principle that payments to a jurisdiction where the actual tax on the payments is less than 75% of the tax that would have been paid in Mexico will be considered made to a tax haven.

VENEZUELA said that it is raising the royalty tax on foreign producers of heavy crude oil in Venezuela from 1% to 16.6% per barrel of oil.

President Hugo Chavez / *continued page 27*

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not render a wind project unfinanceable if curtailment risk is perceived to be low. In this event, the developer may call upon a transmission consultant to analyze curtailment risk (and hopefully reach the desired conclusion) and report its findings to the developer and its lender.

Windpower projects may also have to schedule deliveries of electricity over the transmission grid. If the developer schedules delivery and then the electricity is not produced because of a failure of the wind or otherwise, imbalance charges may result. This makes good wind forecasting important, but scheduling issues may also be addressed in other ways. Again, the nature of the problem and the manner in which it is addressed is largely a function of the rules governing the applicable transmission system. Under certain transmission regimes, windpower projects may be exempted from imbalance charges or such charges may be netted on a monthly basis, making imbalances much more manageable. Under other regimes, imbalance charges are calculated and assessed over much shorter time periods so that it is more important that the offtaker assume this risk. Offtakers may be willing to do so, though sometimes at a price to the developer.

A fairly well developed risk-allocation regime has evolved for windpower projects.

Construction and Technology Risks

The construction risks incumbent in a windpower transaction are similar to those found in any power project and are addressed in familiar ways. Optimally, a developer will contract with an experienced and financially strong contractor under a contract containing clear and strong schedule and performance requirements and incentives, including rigorous performance tests. These provisions should be designed to provide strong contractual assurances that the project will be completed on schedule and meet the production levels contemplated by the project's power purchase agreement. Construction risk is low relative to a more traditional power project because constructing a wind project is not as technically complex and typically requires only six months substantially to complete.

Technology risk is a more serious concern in wind projects. Windpower technology has made tremendous strides over the last two decades resulting in far larger and more efficient wind turbines. However, this progress has meant that wind turbines have gone through two generations of technology in the last ten years with the inevitable problems that new technologies present. The simplest way to address technology risk is to use commercially-proven technology. However, given the rapid pace of technological evolution, this may not be the most economic option.

Technology and performance risks in windpower transactions are principally allocated to the turbine supplier or contractor through a fairly extensive set of warranties. Key turbine warranties include a warranty against defects in design, manufacture, installation or construction or a failure to comply with applicable specifications or law (a "general warranty"), a power curve warranty, an availability warranty and a serial defect warranty, among others.

In determining the adequacy of the warranty package, industry participants note some key considerations: Is the turbine a commercially-proven model with a good track record or is it a new or relatively new model? If it is a new or relatively new model, does it incorporate significant or only incremental changes compared to existing models? Also, certain turbine manufacturers have many years' experience bringing out new models but do not have deep balance sheets supporting their warranty obligations, while some manufacturers may have deeper balance sheets than experience introducing new turbines.

The remedies for a breach of a general warranty are essentially the same as are found in a construction contract for project finance power plant transactions. The supplier must repair or replace a defective part with a new or factory reconditioned part and pay all incidental costs associated with the repair or replacement. Warranty terms for general warranties in windpower transactions are somewhat longer than in power projects using more established technology and generally range from two to five years. Repaired or replaced parts are rewarranted for the longer of the remaining warranty period or an agreed period of usually one year. A general warranty will exclude damage due to ordinary wear and tear, deficient maintenance, excess wind turbulence or temperature or *force majeure* events.

Under an availability warranty, a supplier will warrant the availability of each wind turbine to produce power. Availability warranties typically warrant availability of 95% to 97%, marginally less than the expected availability of 96% to 98%. Availability is measured as a ratio of total hours during a measurement period when a turbine is ready to produce power to the total hours during that period. In calculating total available hours, the supplier is not responsible for hours lost due to events like *force majeure*, curtailments, interconnection failures or the like, but is responsible for downtime due to turbine defects and excessive scheduled repair times.

Remedies for breaches of an availability warranty are intended to replace revenue losses resulting from the shortfall and, as such, are typically calculated based upon the energy price in the power purchase agreement and loss of production tax credits and other economic benefits (such as renewable energy credits) and may be determined based upon an agreed formula or the actual loss suffered by the developer. The supplier may also earn a bonus for availability above the 95% to 97% range.

A power curve reflects the power output of a wind turbine at specific wind speeds. A supplier will typically warrant that the actual power curve of the turbines comprising the wind farm will equal 95% to 98% of the warranted power curve, as calculated based upon a test of a representative sample of the project's wind turbines over a specified test period. The supplier generally has the right to modify the turbines and retest them to attempt to achieve a better result. If the supplier fails to meet the warranted power curve, it typically must pay the developer / continued page 28

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made the announcement on October 10. The tax increase is effective immediately. It applies mainly to multinational oil companies operating in the Orinoco region and is expected to cost the companies $1.27 billion a year. Chavez said a 1943 hydrocarbons act sets the tax at 16.6%, but that foreign companies have managed through "loopholes" to pay only 1%.

Sponsors of four existing oilfield projects with the state oil company as a partner are attempting to negotiate a lower tax before they commit to any future expansions of the projects.

PERU adopted a temporary 0.6% tax on assets.

The tax will be in effect for only two years — in 2005 and 2006. It must be paid in nine installments during the year. It applies to all companies with annual earnings of more than about $1.5 million. The Peruvian Congress adopted it on November 26 by a vote of 42 to 32, at the request of the government, in order to close a budget gap.

In the meantime, two other taxes were eliminated. The Constitutional Tribunal, the country's highest court, struck down a law on November 11 that requires most companies to pay a percentage of their anticipated income taxes in advance of actually earning the income. The tribunal said the tax was unconstitutional because it was imposed on income that did not yet exist.

The business community also succeeded in persuading Congress to repeal a 1.7% supplementary payroll tax. Congress voted to repeal the tax on October 20. The tax disappeared on December 1.

Finally, new regulations issued by the tax authorities in October make it harder to do back-to-back loans into Peru to take advantage of a reduced withholding tax rate on interest paid to unrelated foreign parties. Interest is normally subject to withholding tax at a 30% rate. However, the rate is only 4.99% on interest paid to an unrelated / continued page 29

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an amount reflecting the economic harm to the developer resulting from such shortfall, usually for 12-month periods. There may be some offset between the availability warranty and the power curve warranty to ensure that the developer is not compensated twice for the same loss. Power curve warranties generally are limited to the same term as the general warranty, although some have extended for longer periods, including up to the useful life of the turbines (typically 20 years), where the turbine is a new, unproven model incorporating significant changes relative to existing proven models.

Suppliers may also offer a "serial defect" warranty especially for a relatively new turbine series. The serial defect warranty is intended to address the situation where a major component of a wind turbine is found to be defective in a significant number of turbines. The serial defect warranty reflects industry experience with a number of turbines that have had to be recalled or reengineered. If a component is found to be defective in a certain percentage of the project's wind turbines, the supplier may be required to reengineer and replace the defective component for all of the wind farm's turbine of the same type. The developer may also press the supplier to provide serial defect coverage where a serial defect is found in the same turbine at other wind farms.

Technology risk is also addressed by obtaining independent technical certification of the windpower project from one of the companies providing this service, such as Germanischer Lloyd WindEnergie GmbH or Det Norske Veritas. These companies typically apply wind turbine and wind project certification standards promulgated by the International Electrotechnical Commission (IEC). Wind turbine "type certification" is based upon a design evaluation, type testing (load measurements, black test, power performance, safety and function test), manufacturing evaluation and final evaluation. Project certification includes a site-specific assessment of the turbines and turbine specifications used in the project.

The lender's approach to technology risk is essentially a due diligence exercise. A lender will assess the turbine selection based upon its operating history and manufacturer. It will also typically require a 20-year site-specific design certification by one of the independent technical certification companies. A lender will also assess whether the warranty package is adequate.

Lenders look for a debt service coverage ratio of 1.5 to 1 based on a P50 case and a ratio of 1 to 1 for a P90 or P95 case.

Finally, as is the case in any power project financing, a lender will require that an independent engineer conduct a technical review of the project and prepare a report confirming, among other things, the adequacy of the project's overall wind farm design and that the wind turbines will operate materially in accordance with their design specifications.

Operating Risk

The nature of a wind project makes a strong operations and maintenance regime essential — developers are paid and production tax credits accrue for energy produced. O&M risk in windpower projects is handled in a fairly traditional way. Typically, the developer enters into an O&M contract, either with an O&M affiliate company (where the developer is part of an organization with strong operational experience) or with a third-party company, usually the turbine vendor (where the developer and its affiliates lack operational experience or capacity). A developer may also enter into a long-term service agreement with the turbine vendor pursuant to which the vendor provides routine and non-routine maintenance services. These agreements are usually coterminous with the warranty period under the turbine warranties. Of course, these agreements are at a price to the developer and some developers with strong "in-house" operations and maintenance capabilities may choose to forgo long-term service agreements and instead "self insure."

A lender will assess whether the operations and maintenance package of contracts and in-house capabilities are sufficient in making its decision whether to lend to a wind project developer. An independent engineer will also monitor the operations and maintenance of the project for the lender to assure that good O&M practices are followed. In some instances, equity investors in wind projects also insist on having an equity owners' engineer to monitor the O&M provider's performance. In addition, lenders will require developers to establish maintenance reserves against future scheduled and unscheduled maintenance costs.

Tax Risk

Federal production tax credits provide approximately one-third of the capital cost of a wind project. In some states, state production tax credits may provide additional value. Thus it is essential that one of the owners of a windpower project have taxable income against which the production tax credits may be used. Where the developer of a wind project lacks a tax appetite, the developer will typically sell a portion of the project company (a limited liability company or limited partnership) to an investor with such an appetite. The limited liability company or partnership agreement will then allocate substantially all of the tax benefits (ranging from a 90/10 to a 99/1 split) from the project to the investor for the 10-year production tax credit period or until the investor achieves a specified internal rate of return (IRR), at which point there is a "flip" in ownership interests in favor of the developer ranging from (20/80 to 5/95). Some developers structure their transactions so that they receive distributions of cash until their capital is returned, after which all cash and tax allocations flow to the tax-driven investor until a return hurdle is met.

Between a developer and an investor, the risks of the project qualifying for the production tax credits will typically be borne by the developer. This risk allocation is effected through representations made by the developer either enabling a conclusion that production tax credits are available (*e.g.*, the turbines were placed in service by December 31, 2003) or expressing the conclusion itself. The developer's representations are typically backed by an indemnity and the indemnity is secured / *continued page 30*

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foreign lender. Some companies funding operations in Latin American countries have interposed a bank. The new regulations require Peruvian corporations borrowing money abroad to get a certificate from the lender stating that the loan does not conceal a transaction between related parties.

DIVIDENDS that US shareholders receive from foreign corporations sometimes qualify for tax at a reduced rate of 15%.

The IRS answered questions about when the lower rate applies in mid-October.

The lower tax rate can only be claimed by individuals — not corporations. It will remain in effect only through 2008 unless extended by Congress. Dividends from a foreign corporation qualify only in three circumstances. They qualify if the foreign corporation is incorporated in a US possession, like Puerto Rico or the US Virgin Islands. They qualify if the dividend is paid on shares of a foreign corporation that are "readily tradable on an established securities market in the United States." An example is dividends paid on American depository receipts, or "ADRs," that are traded on a US stock exchange.

Dividends paid by a foreign corporation also qualify if the foreign corporation is entitled to benefits under a "comprehensive" tax treaty between its country of residence and the United States, but only if the treaty has provisions requiring the sharing of information between tax authorities in the two countries.

Certain types of foreign corporations are ineligible. An example is any foreign corporation that the US tax laws label a PFIC — or "passive foreign investment company." This is a foreign corporation that earns a large amount of dividends, interest or other "passive" income or a sizable percentage of whose assets are the kinds of assets that generate such income. Foreign corporations are not PFICs if a majority of the shares are owned by / *continued page 31*

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by developer security, including potential redirection of developer distributions to the investor.

In a financing, production tax credits are monetized through a capital contribution agreement made by the investor in favor of the project company. A lender views the capital contribution cash flow as an important part of the overall revenue stream supporting the loan and thus, while a lender is willing to take the risk that the wind may not blow and energy may not be generated for sale under the power purchase agreement and the production tax credits may not be created, a lender is not willing to take tax or change-in-law risk. Accordingly, the capital contribution obligation is conditioned only on the wind, and capital contributions must be made on the basis of the value of production tax credits that should have been earned as a result of the wind farm producing power even if the investor does not have the ability to use credits, the credits are repealed by the Congress, or the turbines are not placed in service by the deadline for qualifying for tax credits (currently December 31, 2005). However, an investor may not actually have to make the capital contributions in full to the extent that the capital contributions are not required to achieve specified debt service average ratios.

Wind risk may also be addressed through derivative products.

Environmental Risks

Although generally perceived as an environmentally-friendly means of producing electricity, wind farms are not free of environmental issues. The most significant concerns are bird fatalities (including migratory birds and raptors) and, more recently, bat fatalities, as well as noise and visual impacts.

Noise and visual impact concerns have not caused significant problems for wind farm developers (although the potential visual impact of a wind farm in development off-shore of Cape Cod has mobilized some prominent local property owners). This is particularly the case for wind farms located on remote sites. In addition, developers obtain noise warranties from the turbine suppliers. Under these warranties, the turbines are warranted not to exceed certain noise levels at specified wind speeds. These warranties are set at noise levels that ensure that any local noise ordinances will not be violated. The construction contract or turbine supply agreement will also contain specifications for the wind turbines, blades and towers that may be intended to produce a less offensive visual impact.

The issue of bird fatalities is typically addressed by the developer commissioning comprehensive avian studies to determine whether the wind farm site is on a migratory bird route or in an area where raptors are found. If bird fatalities are anticipated and those birds are part of a threatened or endangered species, the developer will need to obtain an "incidental take" permit from the US Fish and Wildlife Service (USFWS) . Any applicant for an incidental take permit must submit to the USFWS a conservation plan that specifies, among other things, the impacts on the affected species resulting from the construction of the wind farm and the steps the developer will take to minimize and mitigate such impacts.

Technology also plays a role in mitigating against, or potentially increasing, the risk of bird fatalities. The turbine supplier will typically warrant that the wind turbine structures do not have features that are attractive to birds (such as ledges on which birds might perch). Also, the majority of migratory birds fly at heights above 100 meters. This means that larger turbines may pose a greater risk to migratory birds than smaller ones. In addition, under Federal Aviation Administration rules, structures 200 feet or higher within a certain proximity to an airport must have lights. Structures below 200 feet and within 20,000 feet of a runway might also have to have lights, depending on the results of a site survey conducted by the Federal Aviation Administration. Any lights might attract migratory birds, particularly on cloudy nights where natural navigation aids (like the moon and stars) are not visible.

APE — An Argentine Tale

by Rohit Chaudhry in Washington, and Carlos Albarracín in New York

Banks and other creditors are developing creative ways of restructuring distressed companies in Argentina. Their experience with the new restructuring procedure called APE has not been entirely satisfactory.

APE stands for *acuerdo preventivo extrajudicial*.

It is a procedure in Argentina, like a pre-packaged bankruptcy in the United States, where a privately-negotiated debt restructuring, supported by a qualifying majority of a company's creditors, can be imposed on recalcitrant creditors. The plan is filed with an Argentine court for approval. Once court approval is obtained, the terms of the restructuring are binding on all creditors affected by the APE, whether or not they were part of the qualifying majority that supported the terms of the restructuring.

During the last three years, companies in Argentina have spent significant amounts of time reformulating their businesses and negotiating restructuring plans with their creditors. A large majority of these distressed companies have used APE as the preferred way of implementing their restructurings.

However, as APE filings have progressed at a slow pace and have become increasingly litigious, in recent months companies and their creditors have begun viewing the APE as a less desirable restructuring vehicle than they originally anticipated. This change in perception has forced companies and their creditors to rethink their restructuring strategies and to come up with more creative and incentive-oriented approaches to restructurings.

Background

The Argentine bankruptcy laws were amended in May 2002 in response to the economic collapse. (For / continued page 32

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US persons each of whom owns at least 10% of the shares.

With that background, the IRS said in October that the 15% rate cannot be claimed on "subpart F income" — or corporate earnings that are taxed to US shareholders under lookthrough rules without waiting for the foreign corporation actually to pay a dividend.

However, it does apply to "section 1248 inclusions." A foreign corporation might accumulate earnings without distributing them as dividends to shareholders. Later, when a shareholder sells his shares, he will receive a higher price that reflects the undistributed earnings still parked in the offshore corporation. In the distant past, shareholders might have tried to do this to get capital gains rates on the earnings. However, section 1248 of the US tax code recharacterizes part of the sales proceeds — up to the amount of undistributed earnings — as a "dividend." The IRS said any such recharacterized income qualifies for the 15% rate.

The IRS also said that whether dividends from a foreign corporation that is a PFIC qualify must be made on a shareholder-by-shareholder basis. Thus, dividends paid to one shareholder might be taxed at the 15% rate while dividends paid to other shareholders are not. In general, since January 1, 1998, a corporation cannot be a PFIC if a majority of its shareholders are US persons each of whom owns at least 10% of the shares. The agency cautioned that if the foreign corporation was a PFIC before this date, then it remains a PFIC and its dividends will not qualify for the lower tax rate.

The IRS guidance is in Notice 2004-70.

The 15% tax rate has complicated foreign tax planning for outbound investments by US private equity funds. To the extent the funds raise capital from individuals, they have had to pay attention in structuring offshore investments to take advantage of the 15% rate. / continued page 33

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earlier coverage, see the *NewsWires* for February and June 2002.) Among other changes, the 2002 amendments let distressed companies and their creditors use the APE, upon endorsement by the court, to bind all creditors affected by the APE, including dissenting and non-participating creditors. In addition, the amendments provide that upon filing of an APE all claims against the distressed company that are affected by the APE are frozen.

Before the 2002 amendments, debt restructurings were accomplished primarily through *concurso preventivo* proceedings, which are similar to chapter 11 proceedings in the United States. The out-of-court restructuring agreements under the APE procedure that existed prior to the 2002 amendments were not popular because they were not binding on creditors that were not parties to the agreements and did not bar litigation related to the restructured claims. They led in many cases to legal challenges and then to the distressed company filing for *concurso preventivo*.

Under the amended APE procedure, a company that is in default or in general financial distress may enter into an out-of-court restructuring agreement with its creditors — just as before. However, as a result of the 2002 amendments, upon filing of such an agreement in an Argentine court, all claims against the distressed company that are affected by the APE are frozen. Further, upon court endorsement, the agreement is binding upon all creditors.

In order to implement an APE, the executed restructuring agreement must be filed in an Argentine court for endorsement, together with supporting documentation such as a statement of assets and liabilities, a schedule of creditors and a schedule of outstanding litigation.

Court endorsement of an APE requires the consent of holders of a majority in number and two-thirds in total outstanding amount of the affected unsecured debt. Unsecured creditors that are also controlling shareholders of the distressed company are not taken into account when determining the qualifying majorities.

In a *concurso preventivo* proceeding, the consents to the restructuring plan typically would have to be obtained by the distressed company at the end of the restructuring process, which commences upon the filing of a petition seeking relief. In contrast, in an APE, the consents are generally required up front at the time of filing of the APE. However, in certain cases, APEs have been filed without obtaining the required creditor consents. This has allowed a company to get the benefit of the freeze on all claims affected by the APE while it sought support from a qualifying majority of its creditors.

Banks have not had an entirely satisfactory experience in Argentine workouts with the new restructuring procedures.

A company and its creditors are free to restructure as they see fit. The APE rules provide for almost no substantive review of the restructuring agreement by the APE court. Once a petition for court endorsement has been filed, it must be publicly disclosed by publishing notice of the filing for five days in Argentine newspapers and in the official gazette. Creditors then have 10 court days to file objections. Objections can only be filed on the ground that the company overstated or understated its assets or liabilities or on the ground that the qualifying majorities have not been obtained. If objections are filed, then a further 10 court-day period is provided for the production of evidence, after which the court is required to issue its opinion. If no objections are filed, then the judge must endorse the APE simply upon verification that the necessary documentation has been filed and the qualifying majorities obtained. Thereafter, objecting parties and creditors have a period of six months after endorsement to challenge the endorsing court's decision.

Theory vs. Practice

Although in theory the APE rules provide an expedited mechanism for restructurings, the reality has been that APE restructurings have been litigious, complex and time-consuming.

While it is clear that the time periods involved in a restructuring implemented by means of an APE are far smaller than the typical two to four years required in *concursos preventivos*, these time periods are far in excess of what was originally contemplated under the statute. The APE rules are, in many important aspects, vague and incomplete. Over the last couple of years, numerous court decisions have shed new light on these provisions. In addition, since the 2002 amendments, numerous Argentine bankruptcy law commentators have theorized about the application and interpretation of the APE rules and their interplay with the rules governing *concursos preventivos*. However, ambiguities remain that result in delays and conflicting interpretations.

The duration of the APE process is one problem. The rules provide an expedited timetable for endorsing the APE once it is filed with an Argentine court (five days for publishing notices of an APE filing plus 10 days for the filing of objections and an additional 10 days for addressing any such objections and issuing the endorsement decision). However, this statutory timetable has rarely been followed. In practice, it has taken up to one year from the filing of an APE to obtain court endorsement.

Such delays have resulted from a number of factors ranging from the substantial delays in declaring the process commenced and the admission of challenges from alleged creditors who failed to make even the most basic case that they are affected by the APE to the filing of appeals to an APE based on the unconstitutionality of the 2002 amendments to the Argentine bankruptcy laws. For instance, in the *Multicanal* APE, the court delayed its decision to endorse the APE for several weeks as a result of a challenge filed by a Paraguayan company that was suing Multicanal in Paraguay in connection with indemnity issues under a stock purchase agreement. The Paraguayan company argued that *Multicanal* "had omitted such entity from the schedule of creditors and understated its liabilities." However, under Argentine accounting principles, it was clear that the lawsuit did not have to be recorded as a liability by *Multicanal* and, therefore, the claimant */ continued page 34*

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DISGUISED SALES of partnership interests get attention from the US tax authorities.

A partner in a partnership might sometimes try to sell part of his interest to someone else but structure the deal so that it is not taxed as a sale. For example, a third party joining the partnership might make a cash contribution to the partnership. The cash is then distributed to one of the existing partners. Cash distributions are normally not taxed. Gain from a sale would be.

The Internal Revenue Service proposed new regulations in late November that identify arrangements that the government will treat as disguised sales of partnership interests. In general, whenever one partner makes a capital contribution to the partnership and all or part of the capital is then distributed to another partner within two years, the partner receiving the distribution will be treated as having sold part of his interest. This is a presumption. The partner may be able to rebut it. The IRS listed 10 factors that tend to point to a disguised sale.

There is no disguised sale when a partnership uses cash just contributed by a new partner to redeem the entire interest of an existing partner. The main tax consequences of a liquidating distribution by a partnership to an exiting partner are the same as if he had sold his interest.

A LESSEE had to pay sales taxes not only on rents, but also on the "additional rent" that the lessor collected for annual property taxes.

One lesson may be to try to have the lessee pay such taxes directly.

Most states collect sales taxes on the rents that a lessee pays for the use of equipment or other "personal property" (as contrasted with real estate). In Louisiana, the law requires that sales taxes be paid on the "gross proceeds derived from the lease or rental of tangible personal property" or on the "monthly lease or rental price paid by lessee." */ continued page 35*

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appeared to lack standing to oppose the APE.

Delays of up to one year have occurred even in cases where creditor support was as high as 90%. In *Sideco Americana,* it took three months for the court to declare the process commenced after the filing date, even though the APE rules provide that the process should commence "upon filing of the APE." In addition, the *Sideco Americana* court delayed its decision on endorsement as a result of objections filed by third parties who neither held loans, bonds or any other claims of *Sideco Americana* nor proved standing to oppose the APE. The table on page 38 lists cases where the APE approval process has taken longer than the statutory timetable.

APE is supposed to work like a pre-packaged bankruptcy in the United States.

The delays raise special concerns for restructurings in the energy and utility sectors in Argentina, above and beyond the concerns one might typically expect a creditor to have in any delayed closing. This is because in these restructurings, in addition to the distressed company and creditors, the Argentine government is very often the unseen third party at the negotiating table.

Over the last few years, the Argentine government has been looking for ways to overcome the crisis in the energy and utility sectors by requiring additional investments by private companies in these sectors. Needless to say, such investments have not been voluntarily forthcoming from the players involved.

As a result, the Argentine government has been looking to use different degrees of coercive measures to compel the existing companies in these sectors to make further investments. For example, the Argentine government is contemplating creating "financial trusts" for making these investments and ordering private companies to divest a portion of their future revenues or existing cash to fund these financial trusts. It is not clear how large a portion of future revenues or existing cash the existing companies might be asked to divest to fund these financial trusts.

This threat is magnified by the fact that in many cases Argentine companies stopped paying debt service soon after the commencement of the economic crisis in order to increase leverage over their creditors. Consequently, many of them have large amounts of cash on their balance sheets, which is being eyed as much by the Argentine government as by the creditors of the companies. While the companies generally acknowledge that this cash ought to be used to pay creditors, they are reluctant to make such cash payments prior to APE endorsement in order to maintain their leverage throughout the restructuring process. Any delay in the APE process increases the risk that this cash may not be available by the time the APE is endorsed if the companies are compelled to use the cash for government-mandated investments.

The process for court review of restructuring agreements is another problem. Following the introduction of the APE rules, a number of commentators noted that a novel feature of the new rules was that a distressed company and its creditors could structure the APE agreement in any manner that they deemed fit, and that court review would be limited to verifying compliance with basic legal requirements (requisite majorities, completeness of accompanying documentation, etc.). This principle was initially construed as allowing flexibility for a company to negotiate the terms to be offered to its creditors and provide incentives that could increase the level of support or attractiveness of the offer. However, in practice, Argentine courts have not allowed absolute freedom to companies and creditors in structuring APE agreements. In fact, in most of the APE cases, Argentine courts have borrowed concepts that govern *concursos preventivos* and have performed thorough substantive reviews of these agreements. Moreover, in some cases courts have gone as far as modifying the terms of the APE agreements filed with the court to equate the treatment of consenters and non-consenters or to remove certain features that the court viewed as contrary to bankruptcy law principles of fairness and equal treatment.

Due to such substantive reviews by courts, distressed companies and creditors are now reluctant to include certain terms in restructuring proposals that might otherwise have made the restructurings more robust. For instance, it is not uncommon in restructurings to provide for certain up front cash payments only to consenting creditors (but not to holdout or non-participating creditors) in order to induce creditors to consent to the restructuring. It is not clear whether such payments would pass the fairness and equal treatment tests that Argentine courts apply to APEs. In some restructurings, debtors use coercive measures such as stripping the covenants that run to the benefit of holdout or non-participating creditors. The idea is again to induce creditors to consent to the restructuring in order to receive a more favorable covenant package. It is not clear whether such covenant stripping would be permitted by Argentine courts in an APE.

In the *Multicanal* APE, holdout and non-participating creditors were only given a ratable portion of new notes and a combination of new notes and shares (which were two of the three options offered to consenters) in exchange for their restructured claims, but were excluded from the cash payment offered to consenting holders. To avert the likely risk that the court could find the APE objectionable on the basis of discrimination against non-consenting creditors, the *Multicanal* APE was amended to provide that non-consenting creditors will receive a prorated portion of each of the three options offered to consenting holders. Upon confirmation of the APE, the court required as a condition to endorsing the APE that *Multicanal* provide bondholders who voted against the APE or abstained a 30-day period to elect the same consideration options given to those who voted in favor of the APE. In *Sideco Americana*, where the APE was filed with the support of 95% of the company's creditors, the court required that the APE be amended as a condition to endorsement to provide that non-consenters receive one of the three options available to consen- / continued page 36

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A lessor asked for a ruling from the state tax department on whether sales taxes had to be paid on reimbursements that the lease required the lessee to make for property taxes. The tax department said yes. The taxes would also apply to other costs that the lease passes through for reimbursement by the lessee. The ruling is Revenue Ruling No. 04-086.

STATE TAX CREDITS can be sold and the buyer can deduct his purchase price in the year he uses the tax credits, the IRS said again.

The agency made its latest comments in an internal legal memorandum in late October. A taxpayer could not use historic rehabilitation and low-income housing tax credits in Massachusetts. He sold them for cash to another taxpayer who could use them. The IRS said the buyer of the tax credits could deduct the amount he paid for them in the year he claimed the credits on his state tax return. The IRS reasoned that the buyer bought "property" — the tax credits — and used the property to pay some of his state taxes. Anyone using property to extinguish a debt is treated as if he sold the property for cash and then used the cash to pay the debt. That is effectively what happened in this case.

The internal memorandum is ILM 200445046. The IRS issued a similar private letter ruling in 2003. The ruling is PLR 200348002 and involved state income tax credits for renovating an historic property.

HUNGARY abolished withholding taxes on dividends starting in 2006. The country had already dropped withholding taxes at the border on interest and royalty payments leaving the country. The change is part of a tax reform bill approved by parliament on November 8.

FOREIGN ELECTRICITY SALES do not have to be reported to the IRS as potential corporate tax shelters. / continued page 37

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ters (10-year floating rate notes) instead of a residual and less attractive option provided to non-consenters.

Another issue that has puzzled Argentine companies and has been the subject of extensive debate is when the APE is deemed "performed".

This is critical for debtors because until an APE is deemed "performed," non-performance by the debtor of any obligation under the restructuring plan requires that the reviewing court declare the commencement of liquidation proceedings or *quiebra* (similar to chapter 7 liquidation proceedings under the US bankruptcy code).

Unlike in US chapter 11 reorganization proceedings, an Argentine company only emerges from its *concurso preventivo* when the reviewing court issues a resolution confirming the full satisfaction of all the restructured claims, which may take several years. This principle of Argentine bankruptcy law was undisputed until 2003, when a Buenos Aires court, in apparent contradiction of the *concurso* rules, confirmed a restructuring plan that provided, upon delivery of the new notes to the affected creditors, the distressed company will be deemed to have performed its obligations under the restructuring plan, thereby emerging from bankruptcy. On the theory that this also applies to APEs, Argentine companies restructuring debt through an APE included provisions in their restructuring plans providing that, upon delivery of the new instruments to their creditors, the terms of their APEs will be deemed performed. However, in the recent *Acindar* APE decision, the court rejected the theory of performance by delivery of the new instruments and expressly stated that the principles applicable to *concursos preventivos* that dictate that the reorganization plan is only performed upon full repayment and performance of the obligations in the plan also apply in an APE proceeding. As a result of this decision, the risk for Argentine debtors in an APE is that if the company fails to perform any of its obligations under the restructured debt, then the company could be liquidated, without the possibility of any further restructuring.

Court approval for the restructuring plan is supposed to take 25 court days, but it takes up to a year in practice.

Another issue with APEs is how to count whether one has support from a majority of the creditors. APE rules require the support of creditors representing two-thirds of the total outstanding unsecured debt amount and a majority in number of unsecured creditors. Although this seems simple enough, these calculations can get complicated in the case of noteholders. And the APE rules provide little guidance. There is a procedure governing this issue that applies to *concursos preventivos* that was not expressly contemplated under the APE rules, but that has been upheld in APE cases such as *Multicanal*.

For instance, in the case of headcount majorities, it is not clear how noteholders should be counted. Under the *concurso* procedure, once a noteholders' meeting is called and validly held, all votes of the noteholders of a particular series supporting the APE are computed as given by one person and all votes opposing the APE are computed as given by one person, regardless of the actual number of noteholders of that series that vote in favor of or against the APE. Then, the votes are added to the individual consents of the other creditors included in the APE to determine whether a majority in number of all unsecured creditors has voted in favor of the APE.

Further, it is not clear whether all outstanding unsecured notes need to be counted or only the notes represented at a meeting of holders convened to approve the restructuring. Court decisions have not been consistent on this issue. For instance, in *Multicanal*, the court held that the rules governing *concurso* proceedings also had to be followed for counting majorities in the context of an APE. *Concurso* rules provide that only the notes represented at a meeting of holders convened to approve the restructuring should be counted in the calculation of qualifying majorities. In *Autopistas del Sol*, the APE was endorsed without a noteholders' meeting and, when dismissing an opposition from a creditor, the court in the *Autopistas* case held that the procedures described above were just one of the options for providing consent to an APE but not the only method.

The manner in which qualifying majorities are calculated is extremely important since the method chosen could determine (and, in many APEs, has determined) whether or not qualifying majorities have been achieved. However, there continues to be uncertainty under the APE rules and case law on this important issue.

Section 304 Proceedings

Even if a restructuring pursuant to an APE is successful in Argentina and receives court endorsement, there is a risk that the restructuring may not be honored in other jurisdictions.

If a company's debt is governed by New York law, then a creditor could bring action in New York courts. To address this risk, an Argentine company might seek recognition of the Argentine bankruptcy proceeding in the US in order to, among other things, bar separate actions in the United States. An ancillary proceeding under section 304 of the US bankruptcy code is the mechanism by which this is done.

In order to obtain relief in a section 304 proceeding, certain minimum standards must be satisfied. Until recently, it was unclear whether an APE would satisfy these minimum requirements since a restructuring under the APE procedure occurs outside of actual bankruptcy with less court involvement than in other judicial restructurings. This issue was recently addressed by a US bankruptcy court in the *Multicanal* case.

Multicanal filed a petition under section 304 commencing a case ancillary to its APE. It wanted a temporary restraining order and preliminary injunction to bar two lawsuits commenced by Huff, a noteholder holding a significant amount of *Multicanal's* unsecured debt. Huff wanted a New York court to order *Multicanal* to repay its notes and bar the company from restructuring them through an APE. The US bankruptcy court granted a */ continued page 38*

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US tax rules require US companies to report any transactions to the IRS that generate at least $250,000 in foreign tax credits where the taxpayer holds the underlying assets "giving rise to" the credits for 45 days or less. The major accounting firms were advising US power companies with foreign power plants to make "protective filings" to report their electricity sales after IRS officials suggested that such sales were covered by tax shelter reporting rules. The thought was that the sales generate income on which taxes must be paid abroad, these taxes are then creditable in the US, and the electricity "giving rise to" the tax credits is not held for more than 45 days. All US manufacturers and retailers had potentially the same problem.

The IRS issued an announcement in mid-November to make clear that sales of inventory in the "ordinary course of the taxpayer's trade or business" do not have to be reported. The announcement is Revenue Procedure 2004-68.

A PARTNERSHIP had to report taxable income in the US when one of its partners repaid a loan from a bank. The partner had guaranteed part of the loan.

The partnership borrowed $18.3 million to build an office building. The project was a bust. The partnership sold the building three years after it was built for only $4.1 million. Some of the bank debt had been repaid by then. One of the limited partners had guaranteed the bank that it would receive ongoing monthly interest payments on the loan. The loan was to be repaid largely in a balloon payment at maturity. A settlement was worked out with the bank where the bank took the $4.1 million in sales proceeds and $8.3 million from the partner who guaranteed part of the debt in satisfaction of the loan.

The partnership told the IRS that it had a loss from the sale of the building and an $8.3 million capital contribution */ continued page 39*

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temporary restraining order preventing Huff and the other related entities that filed litigation in the US against *Multicanal* from prosecuting the state court lawsuits or taking action in the US which would interfere with *Multicanal's* restructuring proceedings in Argentina.

In holding that the APE regime is enforceable in the United States and that dismissal of the Huff lawsuit was warranted, the court stated that the APE procedure bears strong resemblance to US prepackaged bankruptcy plans and rejected Huff's argument that the APE has to satisfy all the conditions for confirmation of a chapter 11 case. The court said that the conditions for confirmation of a *concurso preventivo* need not be satisfied either.

Although the bankruptcy court sided with *Multicanal*, it expressed concern about the treatment of US creditors under *Multicanal's* APE and directed the company to remedy what the court perceived as unfair discrimination against US retail holders of *Multicanal's* notes (who were only eligible to receive a discounted cash-only option and were excluded from the combination of notes, cash and shares offered to *Multicanal's* other more sophisticated US and foreign creditors). In addition, the bankruptcy court was troubled by *Multicanal's* criminal actions against creditors and questioned whether US creditors may be subject to coercion by threats of criminal prosecution in Argentina. To address these issues, the court demanded evidence that the criminal actions were not commenced for improper purposes. The resolution of these two issues is still pending in the bankruptcy court.

	Launch Date (APE Solicitation/ Offer to Exchange)	APE Filing Date	Endorsement Date/Closing Date	Restructuring Method Proposed	Restructuring Method Used	Creditor Majorities Obtained	Amount Restructured (in millions of US$)
AUSOL	Mar-03	Dec-03	Apr-04	APE	APE	95%	337
MULTICANAL	Feb-03	Aug-03	October 2004[1]	APE	APE	68%	525
ACINDAR	Mar-03	Dec-03	August 2004[2]	APE	APE	87%	100
CTI HOLDINGS	Aug-03	May-04	Dec-03	APE	APE	92.90%	310
SIDECO	Nov-03	Dec-03	Jul-04	APE	APE	94%	170
TELECOM	Jun-04	Oct-04	Pending	Parallel APE/ Exchange Offer	APE	94.5%	2,700
BANCO HIPOTECARIO	Dec-03	Jun-04	(APE Rejected October 2004)	Parallel APE/ Exchange Offer	Exchange Offer	97%	1,205
BANCO DE GALICIA	Dec-03	N/A	May-04	Parallel APE/ Exchange Offer	Exchange Offer	98.20%	1,320
HODRELECTRICA PIEDRA DEL AGUILA	Feb-04	N/A	Jun-04	Parallel APE/ Exchange Offer	Exchange Offer	92%	280
TGS	Oct-04	N/A	Dec-04	Parallel APE/ Exchange Offer	Exchange Offer	99.70%	1,026
MASTELLONE	Mar-04	N/A	Oct-04	Parallel APE/ Exchange Offer	Exchange Offer	97.80%	340

1 Appeal Pending
2 Appeal Pending

Outlook

As a result of the increasingly contentious nature of, and uncertainties and delays associated with, the APE process, distressed companies and creditors are exploring other ways of restructuring debt.

In many recent APEs, the restructuring proposals have included parallel restructuring options depending on the level of creditor support. Under these restructuring proposals, if creditor consent exceeds a specified high threshold (typically more than 95% or 96%), then instead of an APE, the restructuring is consummated by means of a voluntary exchange offer. However, below such threshold, the APE procedure is used since the level of holdout creditors then becomes too high for an exchange offer.

In the recent TGS restructuring in Argentina, a more creative version of these parallel exchange/APE options was utilized. In TGS, in addition to the 96% threshold for an exchange offer without an APE, a second threshold of creditor consent was introduced. If this threshold, which was set at 85%, was reached, then the restructuring was to be implemented by means of both an APE and a voluntary exchange. Under this option, the debtor would file an APE.

However, instead of waiting for the APE to be endorsed, the consenting creditors were to exchange their debt pursuant to an exchange offer that would be consummated while the APE was pending. This exchange offer for the consenting creditors within the APE procedure was to be consummated within a few days after the filing of the APE, thereby allowing the consenting creditors to receive their exchange notes and cash consideration up front, instead of waiting for the APE to be endorsed. The holdout and non-participating creditors would receive their new notes and remaining consideration upon a "cramdown" when the APE was endorsed by the Argentine court. However, since the majorities received in the TGS case exceeded the 96% threshold for an exchange offer, the restructuring will be implemented by means of an exchange offer without the filing of an APE. Hence, the idea of an exchange during an APE remains untested in Argentina.

Another recent development is an amendment to the APE rules that was passed by the Argentine Senate in December 2003. The amendment would reduce the qualifying majority required to approve an APE from two-thirds to 51% of the unsecured debt. The headcount majority requirement would remain unchanged. The / continued page 40

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from one of its partners.

The IRS said the $8.3 million had to be reported as taxable income by the partnership, and a US appeals court agreed in mid-November.

A borrower ordinarily has income when a third party pays his debts. The partnership had two arguments for why it should not have to report the $8.3 million as income. It argued that the partner was paying a debt the partner owed directly to the bank on the guarantee. The court rejected this. The partner had only guaranteed ongoing interest payments. It made the payment to get a release from the guarantee. The partnership then argued that the partner had made a capital contribution to the partnership. Partnership do not have to report capital contributions as income. However, the problem in this case was the partner formally withdrew from the partnership shortly before the payment was made.

The case is a warning to be careful of the tax consequences when payments are made by guarantors. The case is Mas One Limited Partnership v. United States.

PENNSYLVANIA is looking at possible changes in the state tax system.

Developers with new projects in the state should take the risk of such changes into account in their pricing.

A commission appointed by the governor to look into possible business tax reforms recommended on November 30 that the state reduce the corporate tax rate from 9.99% to 6.99%, but it said such a tax cut would cost the state a lot of money — even when combined with a tax increase the commission is recommending — and a rate of 7.22% would be revenue neutral.

The commission proposed to make up some of the lost tax money by subjecting limited liability companies, partnerships and S corporations to a 1% entity-level tax. Such entities are not taxed / continued page 41

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amendment would also require that for purposes of calculating qualifying majorities, US dollar debt should be notionally converted into Argentine pesos at an exchange rate of US$1.00 to P$1.00, even though the current exchange rate is far more favorable for the US dollar. The amendment has not yet been approved by the Argentine House. If it is ultimately enacted, then creditors holding dollar debt will be in a less favorable position. ◎

Income Deposit Securities

by Samuel R. Kwon, in Washington

US power companies may be able to use income deposit securities to cash out of power projects.

Coinmach Service Corp. became the third company to use an IDS structure in the United States in November 2004. The owners of Coinmach, a corporation near New York City, offered 18.3 million income deposit securities as a way of selling down equity in the company. The company raised $14.25 to $15.75 a unit for the securities and then used the cash to redeem part of the equity interest of the existing owners. Each IDS represents one share of common stock and one subordinated note. The debt portion of the Coinmach's IDS offering represents an aggregate principal amount of $123.75 million worth of debt. Coinmach leases laundry machines in apartments, and owns and operates retail laundromats.

In December 2003, CenterPlate Inc. (formerly Volume Services America Holdings, Inc.) was the first company to come to market in the US using the IDS structure, raising $277 million, of which $124 million was debt. CenterPlate is a concessionaire in various sports stadiums in the US.

B&G Foods Holding Corp. was the second company to use the IDS structure in October 2004, raising $261 million. Of that amount,$96 million was debt. B&G Foods is a seller of food items, including the Ortega brand.

The securities offer shareholders in closely-held corporations with a stable cash flow and some prospect for growth a way to cash out of such companies. Blackstone Group and GE Capital Corp. used the securities to reduce their holdings in CenterPlate. Bruckmann, Rosser, Sherrill & Co. sold down its ownership of B&G Foods through the IDS structure.

Holders of income deposit securities receive a yield currently in the 10% range.

The IDS structure is still somewhat in flux. B&G Foods has had to amend its filings with the US Securities and Exchange Commission 11 times, significantly altering its dividend policy in the process. Eighteen companies have filed to offer income deposit securities in the last year, representing a potential issuance of up to $9.6 billion, but none except the three companies described earlier has been able to come to market. In September 2004, several companies, including American Seafoods Group and Iowa Telecommunications Services, Inc. abandoned their efforts. Accounting and law firms involved in the issuance of the securities continue to tinker with the structure to get comfortable with the tax and accounting issues posed by it.

Background

An IDS is a security representing one share of common stock and one subordinated note in the issuing company. Its holder receives dividends on the share and interest on the note. The IDS is tradable on a US stock exchange. The investor can separate the equity and the debt piece after a fixed period and can also recombine them later.

In the case of CenterPlate, approximately 60% of the income deposit securities were placed with institutional investors with the remainder going to retail investors. Eighty percent of the investors were in the US and 20% in Canada. The IDS structure was originally envisioned as a way to replicate benefits from Canadian income funds, but in a manner that reduces some of the tax risk associated with that structure. (See the December 2003 *NewsWire* for an article on Canadian income funds.) The CenterPlate securities are listed on both the American Stock Exchange and the Toronto Stock Exchange. Approximately two thirds of the B&G Food's securities were placed with institutional investors and one third was sold to retail investors. Almost all investors in the B&G Foods offering were in the US. The B&G Foods securities are listed solely on the American Stock Exchange.

An IDS may go by another name. A version of an IDS structured by RBC Capital Markets — the lead manager on the B&G Foods offering — is called an "enhanced income security," or EIS. Its Canadian counterpart is called an "income participating security," or IPS. A version marketed by Goldman Sachs is called a "yield oriented unit," or YOU.

Advantages

Investors like income deposit securities because they generate predictable cash flow in an era when many investors have grown weary of accounting scandals and corporate governance controversies. Investors wary of earnings from creative accounting are especially attracted. Current yields are high compared to other investments.

Company owners like the IDS structure because it allows them to sell down their interests in a company well above the 25% commonly sold in traditional initial public offerings of stocks. The types of companies that are attractive to the IDS market — companies that generate stable cash flow, have at least some modest growth prospects, and can tolerate leverage — are typically not well suited for the IPO market where investors are more interested in companies with high-growth potential. The IDS market focuses more on predictable cash flow. Companies using the securities this fall were assigned higher values by the market than are typically achieved through private sales or traditional IPOs, with yields of up to eight times the distributable cash in the case of CenterPlate and B&G Foods. The securities also give companies using them flexibility in whether to pay holders through dividends or interest.

An IDS is valued principally on a yield basis. Essentially, its value is derived by dividing the distributable cash by the yield. Distributable cash is earnings before interest, tax, depreciation and amortization, or EBITDA, minus capital expenditures relating to maintenance, interest on the senior debt borrowed outside the IDS structure, cash tax payments and other administrative expenses. As a result, the companies most suitable for the IDS structure should have a stable cash flow, a modest prospect for growth, and a low potential for unexpected capital expenditure. A company that expects to have to make large capital expenditures is not a good candidate since such expenditures tend to reduce the cash available for distribution, which in turn may reduce the value of the securities.

Structure

Income deposit securities are appropriate only for corporations. The basic structure is not compli- / continued page 42

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currently; income taxes are collected today directly from the partners.

States tax companies doing business in them only on income earned in the state. Most states use a three-factor formula to figure out how much of a company's income is earned in the state. For example, a company that had $100 in income from all its operations might calculate how much to apportion to state X by taking a weighted average of its sales, property and payroll in the state as a percentage of its total sales, property and payroll in all states.

The commission recommended that Pennsylvania move to use solely of the sales factor to apportion income, but that it pool all the income and operations of all affiliated companies into a single, unitary group before applying the sales factor. It also urged the governor to lift a cap of $2 million a year on the amount of net operating losses that a company can deduct.

The governor is expected to use the commission report in drawing up his next budget.

SOUTH DAKOTA is weighing two tax breaks to induce developers to build coal-fired power plants in the state.

The projects are a $1.5 billion new power plant that a coalition of five utilities is considering building near Mobridge or Yankton and a $1 billion plant that a group of six other utilities has studied building on the site of the existing Big Stone power plant near Milbank. The Big Stone plant is owned by Otter Tail Power Company.

South Dakota has no income taxes.

A state utility group has proposed to the governor that the state refund a 2% excise tax that is collected on labor and equipment used in construction projects once the projects are completed; the proposal is to refund the taxes over five years. South Dakota already refunds such taxes to developers of ethanol plants. The other break would be an exemption from annual property taxes for / continued page 43

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cated: the corporation issues securities to investors each of which represents a share of common stock and a fractional interest in a subordinated note. The dividend policy on the common stock is determined by the board of directors, and the IDS holders are not entitled to guaranteed dividends. The subordinated note portion is similar to typical high-yield debt, but its maturity may be longer than 10 years and may have interest deferral provisions.

Income deposit securities are supposed to replicate the benefits from Canadian income trusts for US businesses.

The corporation borrows additional money from third-party lenders as the same time as the IDS offering. For instance, CenterPlate procured additional debt through the private placement market while B&G Foods did the same through the bank market. The reason for the senior debt is to provide additional working capital for the company.

The IDS structure continues to change. Each change is primarily geared towards making sure the debt component of an IDS is respected as an instrument separate from the equity component and is respected as true debt under the US tax laws.

The tax treatment is important because it is essential the corporation be allowed to deduct the interest that accrues on the subordinated note. The first hurdle is a risk that an IDS unit may be treated as a single equity instrument if there is an economic compulsion to keep the debt and equity components of an IDS together. Tax lawyers advise making sure there is enough liquidity in both components to make them severable in practice in the market.

Assuming the debt and equity components are respected as separate instruments, the next hurdle is to ensure the subordinated note part of the IDS is respected as true debt rather than equity parading as debt. Three features typically found in the debt component of an IDS present potential difficulties. First, the debt component of an IDS unit is deeply subordinated, and is usually the most junior debt of the issuer. Second, the interest rate may be too high (and the holders may not care since the same holders also hold the equity). Third, there may be an identity of the equity holders and the debt holders.

The big four accounting firms reportedly have developed five specific requirements to address the tax risk.

First, they recommend that at least 10% of the subordinated notes be placed separately outside the IDS structure. These are called "bachelor bonds." The terms of the bachelor bonds are identical to the terms of the debt portion of IDS. The accounting firms require that the bachelor bonds be sold to investors who are not also holding equity in the corporation. This creates a class of debt holders who are holding notes identical to those forming part of the IDS, but do not hold equity in proportion to their debt.

Second, at least 10% of the common stock of the corporation should be held by other shareholders who do not participate in the IDS. This other equity should not have a right to convert into income deposit securities for some period – for example, two years. These other common shares are referred to as "class B shares." The bar against conversions imposes a real burden on the holders of the class B shares since they stand behind the holders of the income deposit securities in line. The IDS holders are also subordinated lenders and not solely equity holders.

Third, the debt portion of the IDS should rank at least *pari passu* with trade creditors. This is to help distinguish the debt portion of the IDS from merely a more senior tranche of equity.

Fourth, the underwriter of the IDS must represent a current intention to make a market in the bachelor bonds, as well as the separate components of the IDS –- both debt and equity.

Finally, the covenants in favor of the debt holders of the issuing corporation must bar the corporation from paying dividends on shares after an event of default (or in the event the interest deferral period is triggered, if the subordinated notes have this deferral feature). This restriction may be waived or amended only with the unanimous consent of all lenders (including the senior lenders).

One legal advisor involved in the latest IDS offerings said his law firm offered a tax opinion that the IRS "should" respect the debt characterization of the debt component of the IDS and allow the interest payments to be deducted by the issuer. The corporation using the securities took the position that a "should" opinion was enough to avoid having to set up a reserve against the possibility that the IRS would disallow the interest deductions.

Each IDS unit may be separated into its debt and equity components after a time, but separation to date appears rare. For instance, of the 16 million IDS units issued by CenterPlate, during the eight months following the offering, a single holder chose to separate the common stock from the subordinated note.

Follow-On Offerings

The IDS structure allows the issuing company to make "follow-on" offerings of additional IDS units. This is important because in all IDS offerings there will be a retained equity stake by the sponsors in the form of class B stock, and the sponsors will want the ability to exit by exchanging (or converting) their retained equity for IDS units.

Each future IDS unit should be the same as the initial IDS units. If not, the new notes are not the same "issue" as the original notes for tax purposes, the new notes would receive their own CUSIP numbers for trading purposes, and would not be fungible with the original notes. Less fungibility means less trading liquidity. Unlike an initial public offering, an IDS offering is an offering of both stocks and notes. Notes issued at different times may not be fungible with one another because of the possible presence of original issue discount, or OID.

In order to overcome this problem, the financial and legal advisors to the most recent proposed IDS offerings have come up with an "automatic" exchange mechanism. Suppose A buys one IDS consisting of one common stock and one note without OID. Then the company issues an additional IDS to B the next year, consist- / continued page 44

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pollution control equipment used at the projects. Pollution control equipment accounts for about 25 to 30% of the cost of a coal-fired power plant.

The state legislature could be asked to act on the proposals after it reconvenes on January 11.

MINOR MEMOS. The corporate tax bill that President Bush signed on October 22 would reduce US taxes on domestic manufacturing income. Utilities may feel pressure in some states to pass through any benefit from the lower rates to ratepayers by reducing electricity prices. For example, TURN, a consumer group, asked the California Public Utilities Commission in late October to investigate what effect the changes should have on utility rates in California. Income from generating electricity qualifies for the lower rate, but not income from transmitting or distributing the electricity. The new law does not actually reduce rates. Rather, companies are allowed a deduction for 3% of their income from domestic manufacturing in 2005 and 206. The deduction increases to 6% from 2007 through 2009 and to 9% in 2010 . . . . Michigan Governor Jennifer Granholm (D) vetoed two bills in mid-November that would have exempted methane digesters and similar equipment for converting manure into methane from property taxes and authorized the state to make loans of up to $5 million to farmers who want to build ethanol plants or methane digesters or install other equipment for generating electricity from farm wastes and crops. The governor said the state has no money to support the plan.

— contributed by Keith Martin and Samuel R. Kwon in Washington and Jose Ibarra with Chevez, Ruiz, Zamarripa y Cia in Mexico City.

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ing of one common stock and one note with OID. Through the automatic exchange provisions in the indenture governing the issuance of the IDS units, both A and B are viewed each as owning one IDS consisting of one common stock, half a note without OID and half a note with OID.

This means an original holder of an IDS may end up with some notes having OID upon follow-on offerings of IDS unit, causing him to report more interest income than anticipated and having a capital loss (or less capital gain) upon sale of the notes or at maturity. In addition, this automatic exchange mechanism is arguably a taxable exchange for the original holder although there is no clear answer in the US tax laws. None of the filed prospectuses takes a definitive position on the taxability of this deemed exchange.

Three IDS offerings have closed to date. Another 15 companies have filed in the last year to offer such securities.

Uncertainties

Participants in the recent IDS offerings all agree the US Securities and Exchange Commission has still not decided what is the proper level of disclosure required in these offerings. The SEC appears especially concerned that most IDS marketing literature suggests that the debt and equity components together should provide a yield of about 10% when in fact the dividends could be suspended if the company falls behind on payments of interest and principal on its senior debt, and interest payment could be deferred as well. In the case of B&G Foods –- in which there was no interest deferral provision –- the company eventually created a cash reserve of $6 million that it could use to pay investors dividends or to even out the company's cash flow.

Accounting firms have not reached a consensus on the treatment of certain option-like features found in the IDS offerings. For instance, a holder of a class B stock –- retained by the sponsors -– has an option, after a time lag, to convert the common stock into subordinated notes –- identical to the debt portion of the outstanding IDS units –- at a predetermined rate. CenterPlate agreed to treat these options as "embedded derivatives," thus recording approximately $3 million as of March 2004 as a liability for derivatives on its balance sheet. It has promised that "each quarter this option will be fair valued and any change in the underlying value will be either charged or credited to interest expense on the operating statement."

What Next?

Once investors became comfortable with the Canadian income trust structures, many publicly-held companies in Canada converted to that structure. A financial adviser currently involved in preparing a number of potential IDS offerings indicated that one can foresee public companies converting to the IDS structure eventually once the public gains confidence in it. The prime targets for such conversion, or new IDS offerings, would continue to be corporations with assets that generate a stable cash flow, including potentially government-owned infrastructure like toll roads and energy and water projects that may be put up for privatization using the IDS structure. ◎

Grid Separation Proposed in Holland

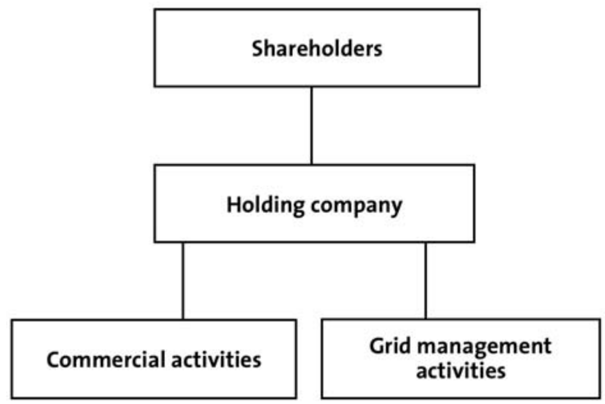
by Machteld van Oosten, with NautaDutilh in New York

The Dutch government presented an action plan on October 11 for restructuring the energy market in Holland.

One of the major changes envisaged is the complete separation of electricity transmission from other energy-related activities, such as generation and distribution. The government plans to introduce legislation prohibiting the simultaneous ownership of shares, whether directly or indirectly, in grid management companies on the one hand and companies active in the generation, supply or trading of electricity and gas on the other. This prohibition will not apply to current shareholders of regional energy companies. Mr Brinkhorst, the minister of economic affairs, said he intends to present the bill to Parliament in 2005 and to have the action plan implemented by January 2007.

Current Situation

At present, the shares in regional energy companies are directly or indirectly held by provinces and municipalities. Following enactment of the Electricity Act in 1998 and the Gas Act in 2000, energy distribution companies that owned a grid were required to designate separate companies as grid managers. Most of the Dutch energy businesses are therefore structured in the form of a grid management company and a separate company to undertake other energy-related activities, with the shares in both companies being held by a holding company under a vertically-integrated structure. This structure is shown in the diagram to the right.



Action Plan

If the action plan is implemented, then this type of structure will no longer be permitted. The government aims to have complete independence of the grid management sector. It believes that this complete independence cannot be achieved if shares in a grid management company and in a company engaged in commercial activities are held by the same shareholders.

The expectation is that full independence of grid management will prevent interests in the grid from being overridden by commercial interests. The economic affairs minister sees an inherent conflict between the interest of consumers in a reliable and high-quality grid and the commercial interests of the integrated energy companies.

The minister also cited a survey commissioned by the Dutch Energy Authority (DTE) showing that the existence of distribution companies that are part of a vertical ownership structure (and hence part of a group that owns a grid) may lead to unfair competition between such companies and distribution companies that enter the market without ownership of a grid. Although legislation setting out stricter rules for the independence and supervision of grid managers recently came into force (the I&I Act), the economic affairs minister considers these rules inadequate to prevent undue influence by the parent company. In addition, the separation will, according to the minister, result in a more transparent company structure, making it easier for the DTE to supervise the energy market.

Provincial and municipal governments that currently hold shares in the regional energy companies will benefit from the separation, as it will allow them to withdraw from energy production and supply activities and free the financial resources tied up in this business. At present, these are effectively locked up because shareholders of energy companies that own a grid are not allowed to transfer their shares outside the circle of current shareholders. This does not apply in the case of companies without a grid. The government believes that the proposed separation of grid management activities is in the best interests of both the consumer and the current shareholders of integrated energy companies.

The recently-enacted I&I Act contains a provision –- that has not yet entered into force –- under which the "economic ownership" of a grid is to be vested in the relevant grid manager. Economic ownership is defined in the I&I Act as "being entitled to all rights and powers in respect of certain property other than the right to transfer the title, and being accountable for all liabilities in respect of that property thus bearing the full risk of loss of value or total loss of such property, / continued page 46

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without title to the property being transferred." The government plans to have this provision enter into force at the same time as the proposed "separation" bill, meaning in January 2007.

The government also wants to expand the authority of TenneT, the government-owned manager of the national high-voltage grid, which currently manages all grids of over 220 kV. Under the action plan, TenneT would be appointed network manager of all grids with a voltage of 110 kV and higher in order to better ensure the reliability of the electricity supply. However, there will not be a legal requirement that TenneT hold economic ownership of the grids it manages.

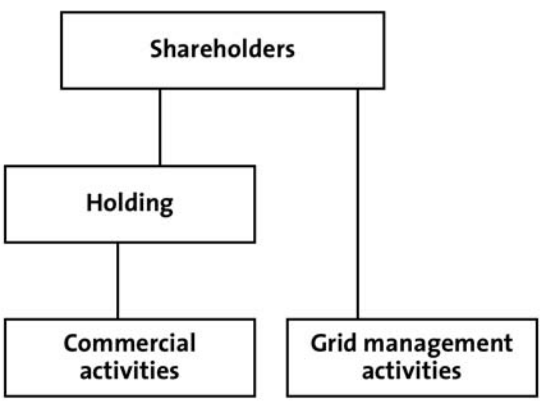
Privatization of grid management companies is currently prohibited at least until 2007. The government is reconsidering the privatization issue and will make policy proposals in early 2005. However, the government has already announced that it is considering allowing the privatization of minority interests in grid management companies prior to 2007, provided the company in question has been "unbundled" as proposed in the action plan and provided that any further conditions set in this connection have been met. The intention is that companies active in the generation, supply or trading of electricity and gas will not to be allowed to hold an interest in a grid management company.

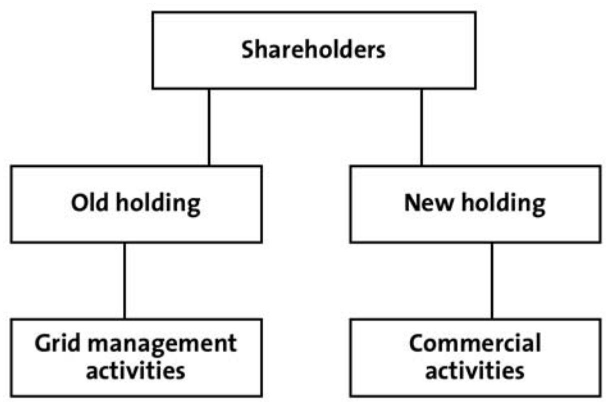
New Structure

Under the proposed new structure the government would like to see adopted, the simultaneous holding of shares in both energy generation, supply or trading companies and grid management companies by the same shareholders will be prohibited.

However, this prohibition will not apply to the current circle of shareholders of regional energy companies, as the government does not want to force them to sell their shares. Consequently, the energy companies will have to split off their grid management activities. This will leave the Dutch energy market divided into commercial companies whose activities will include the generation, supply and trading of energy, and grid management companies engaged in electricity transmission.

According to the action plan, the division of energy companies can be achieved in one of two ways.





In the first scenario, the grid management company is spun off to the shareholders. In the second scenario, it is the commercial arm that is spun off. This can be done by having the current holding company transfer the commercial activities to a separate company, or by carrying out a de-merger. Subsequently, the shares in the commercial company can be sold to a third party, offering the current shareholders the possibility of unlocking their financial resources.

Questions to Consider

In the 1990s, there were a number of cross-border lease transactions in which power plants and grids in The

Netherlands were leased to US investors. Accordingly, economic ownership of the plants and grids was vested in the investors, with the grids subsequently being leased back to the Dutch energy companies in question. The cross-border lease agreements may contain certain requirements with regard to credit rating that will be triggered if the proposed "unbundling" is effected. In addition, the provision in the I&I Act regarding the economic ownership of grids will have to be carefully implemented so as not to generate a potential conflict with the terms of the leases. The government said in the action plan that it considers any consequences for cross-border leases arising from the proposal to be the responsibility of the energy companies so affected.

Before publicly outlining the action plan, the economic affairs minister announced that he was planning to require that grid managers hold legal title to the grids in question in addition to having "economic ownership" as described earlier. However, this idea met with a lot of opposition and was therefore dropped from the action plan.

In The Netherlands, there is no unanimity on the question of who holds legal title to a grid.

Furthermore, it is unclear whether grids should be considered as movable or immovable property, and whether they consist of one or more objects. The Dutch Supreme Court has ruled that cable networks are immovable property, providing a strong argument for grids also to be be considered as such. However, if a grid is considered to be immovable, then the question still remains whether it should be considered the property of the landowner by way of vertical accession. In the bill for the I&I Act, a provision was included vesting legal title to an energy grid in the party that had constructed it or with that party's legal successor, as the case might be. The draft provision did not solve the problem, as it raised several new questions. Until now, the networks have been constructed at the expense of the energy companies in their current structures (owning the grid). What would happen if, under the new structure, the grid manager expanded the grid at its own expense? Would legal title to the extended part of the grid be vested in the grid manager, causing ownership of the grid to be fragmented? In the end, the provision was removed from the bill, leaving the economic affairs minister with too little grip on the issue of legal ownership to be able to maintain the proposed requirement in the action plan. However, it is not clear what the future will bring, as a new bill is on the way that is expected to eliminate this uncertainty with respect not only to energy grids, but also to all similar grids and networks.

The action plan goes beyond current European Union rules. The action plan is part of a bigger picture.

The European Commission has recently issued two directives to start the process of liberalization within the EU and to establish one internal energy market. In order to create a free market system, independent generators should be able to use the existing grids. An EU directive requires grids to be managed by companies separate from those engaged in generation, supply or trading. In The Netherlands, this rule has already been implemented under the 1998 Electricity Act. However, the action plan goes beyond what the European Commission intends and provides for a stricter division, separating not only the entities that manage grids but also the ownership of such entities. The Dutch Council for Energy advised the economic affairs minister against the separation as proposed on the grounds that the resulting difference between Dutch legislation and that of other EU countries could have a negative impact on the position of Dutch energy companies because investors will be more likely to invest in companies that own a grid. The economic affairs minister has said that he considers this argument unpersuasive, as he thinks that Dutch energy companies will eventually be taken over anyway, whether or not they own a grid.

The proposed plan of unbundling can potentially cause adverse tax consequences.

The energy companies have been vocal on this point. Whether there are disadvantages or whether facilities can be used to effect the proposed steps in a tax-neutral matter depends on the specific facts and circumstances of each taxpayer. In any case, the government has said that it will look into the possibility of state support for the companies in order to provide them with relief.

Outlook

The action plan faces an uncertain future in Parliament.

On the same day that the government presented the action plan, the CDA — the largest party in the governing coalition — released a report, drawn up by the party's scientific committee on future policies for the / continued page 48

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Dutch energy sector. One of the views expressed in the report is that it is not necessary to separate the ownership of grid management companies from that of commercially-active companies in order to secure the reliability of energy grids in The Netherlands. The CDA's position is that the independence of grid managers can be sufficiently safeguarded through a combination of strict rules and strong supervision by the DTE on one hand and the preservation by the government of its controlling interest in either grid managers or co-ordinating energy companies on the other, and that separation should be considered as a last resort.

The most recent news on the privatization issue is that most parties in Parliament agree that the energy companies should not be required to separate their activities unless they want to transfer their shares to a third party. However, it appears that many provinces and municipalities wish to dispose of their shares and would therefore have to go through with the separation.

The action plan is scheduled for debate in Parliament on December 8. Hopefully, the debate will shed light on where the energy industry in The Netherlands is headed. ◎

When Is a Lease a Lease?

by Robert J. Gillispie, in New York

A US district court in Illinois said in mid-November that a lease is a "lease" if local law says it is.

The decision is important because bankrupt companies that have leased power plants, airplanes or other equipment must catch up on missed rental payments or risk losing their assets. However, if the arrangement is not really a lease but merely a financing, then the lessor must get in line with other creditors and the bankrupt company can continue using the asset.

The district court was responding to an appeal from a decision by the US bankruptcy court that is handling the United Air Lines bankruptcy. The case is called *HSBC Bank USA v. United Air Lines*.

Background

In 1973, United leased 130 acres at the San Francisco International Airport from the city as a site for ramp space as well as various facilities.

A tax-exempt revenue bond financing was subsequently arranged in 1997 with the California Statewide Communities Development Authority — called the CSCDA — to cover the construction cost of a maintenance facility. As part of the revenue bond financing, United subleased 20 of the 130 acres at the airport to the CSCDA for a nominal rent of $1. The sublease had a term of approximately 36 years. The CSCDA then sub-subleased the premises back to United under a facilities lease, also for a 36-year term. The facilities lease rentals were in an amount sufficient to pay the revenue bonds, administrative costs and reasonable compensation for the use and occupancy of the 20 acres. The CSCDA collaterally assigned the facilities lease, including the right to collect rents, to an indenture trustee who was acting for the holders of the revenue bonds.

United filed for bankruptcy in December 2002.

United immediately found itself in a quandary. It obviously needed the maintenance facility at the airport. If United could persuade the bankruptcy court that the facilities lease was not a "true lease" for purposes of the US bankruptcy code, then United would be relieved of the choice under section 365 of the bankruptcy code to assume the facilities lease, with all the burdensome financial obligations that assumption entails, or to reject the facilities lease and surrender the airport maintenance facility. Section 365 of the US bankruptcy code lets the bankrupt company in a so-called chapter 11 bankruptcy case where the bankrupt company is trying to reorganize rather than liquidate — or a trustee appointed by the bankruptcy court to manage the company's affairs — assume or reject unexpired leases. But the right to assume comes with some strings. If the company wants to keep the lease, then it must cure all defaults (including payment defaults), compensate any party that has suffered a pecuniary loss from the default and provide adequate assurance of future performance under the lease.

If, however, United could have the facilities lease characterized as merely a "financing," then United would be permitted to retain the airport maintenance facility, and the CSCDA (and the indenture trustee as security assignee) would be relegated to secured lender status, if appropriate steps had been taken to "perfect" its security interest, or unsecured lender status, if not.

Lease?

United argued, and the bankruptcy court agreed, that the facilities lease was not a true lease for purposes of section 365 of the bankruptcy code. The bankruptcy court found that the facilities lease was, under federal law as opposed to state law, the "economic equivalent of a leasehold mortgage"; in other words, the airport maintenance facility was merely security for a loan.

The term "unexpired lease," as used in section 365, is not defined in the bankruptcy code. Accordingly, courts have relied upon legislative history of an analogous section of the bankruptcy code, namely section 502(b)(6) which limits damage claims from terminations of real estate leases. The relevant legislative history states: "Whether a 'lease' is a true or bona fide lease, or in the alternative, a financing 'lease' or a lease intended as security, depends upon the circumstances of each case. The distinction between a true lease and a financing transaction is based upon the economic substance of the transaction and not, for example, upon the locus of title, the form of the transaction or the fact that the transaction is denominated as a 'lease'." Based on this legislative history, courts have required a lease to be a "true" or "bona fide" lease for section 365 to apply.

The bondholders appealed the decision by the bankruptcy court that the facilities lease was merely a financing document. The appeal went to a US district court in Illinois.

The district court observed that Congress has generally left the determination of property rights in the assets of a bankrupt company to state law, with the caveat that state law may be displaced with a federal common law if "some federal interest requires a different result." Finding no "clear and manifest" statutory purpose to displace traditional state law, the district court applied California law in determining whether the facilities lease was a true lease for purposes of section 365.

Under California law, an agreement is presumptively a lease of real property if it is called a lease by the parties, contains a definite description of the leased property, provides for periodic payment of rent for the term of the lease and provides a right to occupy the property to the exclusion of the lessor.

The facilities lease met these touchstones and was, therefore, presumed to be a true lease under California law. The presumption could have been rebutted if United had established that the parties intended something else — for example, if they had intended to use the facilities lease to disguise a sale of the airport maintenance facility or to act merely as an encumbrance on the maintenance facility. The intention of the parties is determined by reviewing all facts and circumstances of the transaction, including the underlying economic substance. Factors considered by the district court in this case were: whether the facilities lease transferred risks and responsibilities that would normally be borne by a landlord to the lessee, whether the payments under the lease are reasonably designed to compensate the lessor for the use of the property or simply to reflect the repayment of the lessor's own financing costs plus interest, and whether the lessor retains an economically-significant interest in the property.

Applying these factors, the district court concluded that the facilities lease was a true lease under California law. While United was required to pay the taxes, upkeep and insurance for the maintenance facility –- obligations typically borne by an owner –- the district court concluded that the use of triple net leases is not unusual in the real estate context.

The district court also determined that the aggregate rental payments required by the facilities lease included an amount needed to amortize the revenue bonds as well as reasonable compensation for the use and occupancy of the 20-acre site.

United argued that because the CSCDA did not retain an ownership interest at the end of the facilities lease, the facilities lease cannot be a true lease. This important factor was the sole basis the bankruptcy court gave for its conclusion that the arrangement was not a true lease. The district court observed that a "lease-leaseback" arrangement as a method of financing is not inconsistent with the existence of a lease. United conceded that it did not own and could not ever own the airport maintenance facility. In fact, it had no option to purchase the facility at the end of the facilities lease. Accordingly, the district court concluded that the lack of a reversionary interest for the CSCDA at the end of the facilities lease did not rule out treating the facilities lease as a true lease.

The bottom line: the facilities lease is a true lease under California law.

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Aftermath

Interestingly, courts that have had to address this issue under the Uniform Commercial Code have similarly struggled with determining whether an agreement should be characterized as a true lease as opposed to a lease intended for security or a financing agreement. Section 1-201(37) of the UCC was amended in response to perceived ambiguities and over reliance on the parties' intent engendered by the old statutory language. Accordingly, amended section 1-201(37) deletes all references to the parties' intent.

As amended, section 1-201(37) provides, in pertinent part, as follows:

> "Whether a transaction creates a lease or security interest is determined by the facts of each case; however, a transaction creates a security interest if the consideration the lessee is to pay the lessor for the right to possession and use of the goods is an obligation for the term of the lease not subject to termination by the lessee, *and*:
>
> (i) the original term of the lease is equal to or greater than the remaining economic life of the goods,
>
> (ii) the lessee is bound to renew the lease for the remaining economic life of the goods or is bound to become the owner of the goods,
>
> (iii) the lessee has the option to renew the lease for the remaining economic life of the goods for no additional consideration or nominal additional consideration upon compliance with the lease agreement, or
>
> (iv) the lessee has an option to become the owner of the goods for no additional consideration or nominal additional consideration upon compliance with the lease agreement."

If the district court's decision in the *HSBC Bank* case correctly articulates the law — United has not yet decided whether it will appeal — then a court would be strongly influenced by the UCC analysis, with the result that a significant residual interest would be the most compelling factor in determining whether an arrangement is a lease. ◎

US Moves to Promote Broadband Over Power Lines

by Dana Frix and Kemal Hawa, in Washington

Can electric companies compete with telephone and cable companies?

Michael Powell, chairman of the US Federal Communications Commission, is convinced they can. He believes that the next big development in communications services will be use of power lines to provide high-speed Internet, video and telephone connections for US homes and businesses — so-called "broadband" services. The FCC adopted new rules on October 25 that are supposed to spur such a revolution.

The main thing the rules did was allow electric utilities to make broadband services over power lines widely available to their customers.

Utilities had been allowed to offer such services in the past on a limited basis. The main impediment was fear by ham radio operators, government emergency services, the airlines and other users of radio frequencies that widespread access to broadband over power lines would interfere with radio transmissions. The FCC took steps in the new rules to reduce the potential for such interference.

Background

Electric utilities are natural competitors to telephone and cable companies. Electric lines represent one of the few forms of "last mile" access to customers. The only companies with widespread "last mile" access today to customers, which means control over physical facilities that enter individual homes and businesses, are the incumbent telephone, cable and electric and gas utilities. The lack of such access by other companies has proven to be the single most significant barrier to competitive entry into the telephone, cable and Internet markets, since other new entrants must rely upon their primary competitors for such access. New technological advances have made it possible to provide broadband services over power lines.

The FCC faced significant opposition to its plan to open power lines to broadband service from radio operators concerned about radio interference. Broadband-over-power-line services emit radio frequency energy that can interfere with existing public and private uses of radio frequencies. As explained more fully below, the FCC adopted operational requirements for the service to minimize interference with radio operations. It also adopted new measurement and certification guidelines to monitor radio interference. But, its resolution of the issue is in fact imprecise, reflecting the degree to which the FCC believes that its new rules will help spur development of a "revolutionary" new medium and its willingness to take risks in the process.

The FCC believes that the provision of broadband service over power lines will be a worldwide phenomenon. It wants the US to take the lead in developing the new technology required. Its new rules focus in the near term on the development of cost-efficient alternatives for rural Americans to receive high-speed broadband services. In the longer term, the FCC is interested in seeing power companies compete for every class of customer — residential, institutional and commercial.

Broadband services over power lines are not limited to high-speed Internet, video, and telephone access. The electric wiring inside buildings can also be used for a host of new applications, including shared Internet access, shared printing, file sharing among computers, and device control. It can help with setting up home computer networks. The FCC is equally enthusiastic about these potential applications, since each electrical outlet within a home or building is potentially an access point to a variety of broadband services.

Service providers such as Cinergy, Consolidated Edison and Southern Company also anticipate that broadband service over power lines will open the door to a variety of sophisticated power distribution applications, including automated outage detection and restoration confirmation, remote monitoring and operation of switches and transformers, more efficient demand-side management programs and power quality monitoring to detect faulty components before they fail.

This has led the US Department of Commerce to conclude that many electric utilities will deploy power line technology in order to realize these benefits even if they never offer their customers broadband service.

Local governments are also eager to see utilities provide broadband service because it will mean an end to the broadband duopoly of cable modem and DSL (digital subscriber line) service, and may be the only way for many rural communities to get broadband access. Lobbying by local governments provided a counterweight to the opposition from radio operators.

Utilities are expected to earn $2.5 billion a year by 2010 from providing "broadband" services over power lines.

Radio Concerns

The radio operators are not satisfied with what the FCC did. Not only are the rules too loosely drafted in their view, but they also assume that interference will occur, and impose responsibilities on both sides to minimize or avoid such interference.

The new rules require adoption of so-called "adaptive interference mitigation techniques" to minimize radio interference.

What this means is that the FCC barred broadband service on certain frequencies and in certain locations in order to prevent interference with fire, rescue and police radios. In the event of interference, radio operators are supposed to complain to the utilities, which have an obligation in turn to mitigate the interference. The FCC declined to establish entire zones around airports, military complexes, hospitals and the like (as / continued page 52

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some had suggested) where broadband could not be offered at all through power lines.

The new rules require utilities to build in the ability to deactivate specific units found to cause substantial radio interference and to shift operating frequencies to avoid interference in a specific location.

Although the FCC set these requirements, it left considerable discretion for the utilities to figure out how best to implement them.

The FCC plans to set up a publicly-accessible database that identifies the operating characteristics of each broadband system that utilities offer. The database will be organized by zip code. Consistent with its overall deregulatory approach, the FCC has left the problem of how to organize the database for the industry to solve.

One of the most contested issues was how to measure radio emissions of broadband-over-power-line systems. The FCC concluded that the systems must be tested as they are constructed, and that operators will not be able to rely exclusively on laboratory testing. However, only three typical overhead and three underground installations need to be tested (as opposed to testing all the equipment). Equipment vendors must certify conformance with FCC regulations.

Outlook

The United Power Line Council estimates that the broadband-over-power-line market will generate $2.5 billion in annual revenue by 2010, which would only happen if the utilities succeed in just a few years in providing serious competition for telephone and cable companies.

Utilities face a number of obstacles to compete effectively in the broadband market. A recent study said that cost, reliability and quality are identified by consumers as the most important factors in selecting a broadband service provider. Consumers indicated that while they are eager for alternatives to cable modems and DSL, they are skeptical about the ability of their electric utilities to provide services are comparable prices and quality. One approach utilities might consider to overcome consumer hesitation is to partner with a recognized Internet service provider to offer a package of broadband access and Internet services. ◎

Political Risk Insurance in Project Workouts

by Kenneth Hansen, in Washington

The phone rings. Anne shudders. A project financier, she knew what was coming and hated these calls. The project company's chief financial officer would report that sales are off or expenses are up. Net revenues would fall short of upcoming debt service payments. Could they meet to discuss terms for a rescheduling?

This loan is insured against losses from expropriation, political violence or currency inconvertibility or non-transfer, but no such luck here. This deteriorating business would be Anne's problem.

Such calls are not frequent in the world of infrastructure project finance, but they do come. The environments that in recent years spawned a spate of political risk insurance claims — Indonesia, Pakistan, Thailand, Russia and Argentina during their respective economic crises — also gave rise to any number of project loan restructurings either where the investments were uncovered or the conditions for claims were not met. This article explores the role played by political risk insurance and the insurer when the time comes to restructure project loans.

Background

Some brief background on the political risk insurance market — actors and products — may help.

Political risk insurers come in two flavors — public and private. The public agency insurers themselves come in two varieties — bilateral and multilateral. The public side of the industry has been dominated by one bilateral agency, the US government's Overseas Private Investment Corporation (OPIC), and one multilateral, aptly named the Multilateral Investment Guarantee Agency (MIGA), from the World Bank Group. These two agencies — OPIC for US investors and MIGA for everyone else (so long as both their home and target countries belong to MIGA) — until recently constituted the full set of public provider options for equity coverage.

Project lenders have these public sector options plus potentially two more. First, they may appeal to the relevant export credit agencies whose export-promotion programs include "political-only guarantees" of project loans made (if and to the extent that the proceeds are spent in the export credit agency's home country). Second, in a growing number of cases, they might seek "partial risk guarantees" from multilateral development banks.

Complementing the public agency providers is a small group of commercial political risk insurers who offer coverage to both equity and debt investors in emerging market projects.

The core triad of products for which the political risk insurance industry is best known comprises coverages against an investor's losses as a consequence of expropriation, political violence or exchange controls — so-called currency inconvertibility and transfer cover. This has been complemented in recent years by various forms of mitigation against the risk of government breaches of contracts.

While much of the most colorful history of the industry has revolved around expropriations or political violence, the core coverage for project lenders has been against exchange controls.

This cover was invented as part of the US Marshall plan. The idea was to encourage US investors to invest in post-war Europe notwithstanding the prevalence of exchange controls. Participating investors were promised compensation in the event they could not convert payments to dollars or were unable to transfer dollars out of the host country.

Such currency risk insurance became popular with project lenders who were comfortable with a project's capacity to pay debt service but wanted assistance with regulations or rating agencies who were concerned about macro-economic circumstances in the host country blocking access to the project's earnings that would otherwise have been available to pay offshore debt service. Such coverage is now offered by all of the public and private political risk insurers.

A Restructuring Resource

Political risk insurance can both help and hinder the restructuring of a troubled project's outstanding debt. Consider first the value that the existing political risk cover may bring to the process of restructuring project loans.

First and foremost, the insurance coverage continues to defray some risks associated with the now troubled investment. It assures the lenders, who have been disappointed by developments in the project's credit, that they can continue to depend on at least one aspect of the risk profile of the original deal.

If the political environment of the project has deteriorated since the financing closed, then the existing coverage may be an irreplaceable — and thus valuable — asset. Assume a $100 million project loan, insured against political risks, is in trouble. It faces a $20 million cost overrun and a bankrupt sponsor is unable to perform its completion guarantee. The lenders agree to swap $20 million of their debt for equity, lowering the outstanding project debt to $80 million. They intend to seek $20 million of fresh senior debt to finance completion and initial operations of the project. It might well be convenient if, instead of simply losing the benefit of $20 million of insurance coverage on the debt reduction, that coverage could be offered as an enticement to the new money lenders.

The existing coverage is likely to be a bargain even if the host country environment has not deteriorated. The market would probably not be willing to offer the investors terms equivalent to those offered at the original closing. Insurers, whether agency or commercial, are disinclined to step into a troubled project. The underwriters are likely to believe that troubled projects are more likely to end up in political trouble and that insured investors in troubled projects are more likely to try to characterize essentially commercial troubles as political and to file claims.

The likelihood that the agencies would offer fresh cover is even more remote than that the commercial insurers would do so if the project has already been built. OPIC and MIGA, who share the mission of encouraging private investment in developmental projects, would likely point out that new investment in an already-existing project brings no fresh developmental benefit. That presumption might be rebutted if the consequence of a failed restructuring would be the shutdown of the project and the loss of the related jobs and other economic benefits that come from its continued operation. Such an argument for coverage of new investments in an existing project would be taken seriously but it would also be examined closely and resolved on a case-by-case basis. If so-called "political-only cover" from an export credit agency were at issue, the agency would likely reject a request for new guarantees with the observation that they would not bring any new exports.

Even though the existing coverage */ continued page 54*

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may be a bargain under the circumstances, it may not be worth the cost of retaining it. The lenders will analyze the costs and benefits of maintaining the coverage. The benefits will depend in part upon how heavily the lenders weigh the risks that have been assumed by the insurer. Risk mitigation may not, however, have been the sole motivation in procuring the policy. The banks may have acquired the coverage because of its salubrious impact on the loan loss reserves required to be held against uninsured foreign loans. Once restructured, the loan may require substantial reserves notwithstanding the insurance.

A great deal of political risk insurance has been taken out to support bond issues in order to enable the bonds to achieve an investment grade rating otherwise beyond their reach as a consequence of the sovereign ceiling reflecting the credit rating of the host government. If the bonds are now headed for a credit default, or even a downgrade, then the rating that was the likely motivation for acquiring the insurance may be lost. In such circumstances, the value previously attributable to the enhanced rating will need to be deducted from the benefits attributable to the policy. If the rating, rather than risk mitigation, was the prime motivation for paying the insurance premium, then the restructuring may be the end of the lenders', or bondholders', demand for the insurance.

The cost-benefit calculation will also look at the cost of maintaining the policy. If premiums continue to come due, the lenders may well decide to divert those amounts to repaying the project loans. The policy may have been paid in full up front. In that case, maintaining the coverage might be costless. Even if premiums have been fully paid, however, there may be an opportunity cost in maintaining prepaid coverage if a premium refund would otherwise be available. If so, the cash back might well serve more immediate needs, such as immediate debt reduction.

Deciding whether the risk mitigation provided by the policy is worth the price may also involve making a judgment about the likely terms of the restructuring. Will additional parties be brought in? How might they value the political risk insurance?

In any event, whether as a source of risk mitigation, cash back or enticement to new money lenders, political risk insurance could be a resource to work with during a restructuring.

Political risk insurance can both help and hinder a debt restructuring in a troubled project.

Impediments

Political risk insurance could also impede implementation of the preferred terms for a project loan restructuring.

1. *Assignment Issues*

If, as mentioned earlier, the coverage is expected to have value to new investors being brought into the restructured deal, then the coverage will need to be transferable to them. Such assignments typically require the insurer's consent.

MIGA, for instance, requires that:

> The [project lender] shall not without MIGA's prior written consent, which consent shall not be unreasonably withheld . . . assign, transfer, or encumber (a) any right under the [Insurance] Contract, (b) any right, claim, security or other interest related to the Guaranteed Loan, or (c) any right under [an insured arbitral] Award.
>
> Thus, for instance, an assignment of the proceeds of a claim, as well as assignment of the contract itself, requires MIGA's prior consent.

Such consents will typically "not be unreasonably withheld," whether or not the contract so provides. In one circumstance, however, refusal of consent to assignment of the insurance contract would not only be reasonable but probably assured. OPIC and MIGA each have requirements as to the nationalities of the beneficiaries of their coverage. Those requirements will not be waived (though they might be structured around).

Note that the caveat that the insurer's consent "shall not be unreasonably withheld" is important. Absent that limitation on the insurer's consent rights, under New York law, which governs many of these policies, an insurer "may withhold consent for any reason or no reason, and . . . no obligation to act in good faith exists to limit that choice." This is not to say that an insurer would not be inclined to cooperate in consenting to a debt restructuring. The point is only that, absent the magic words regarding "reasonable consent," the insurer has no obligation to so limit the grounds for its refusal to go along with a restructuring plan. Where the insurer is so constrained, the question of just what constitutes "unreasonably withholding consent" arises. That is explored later.

2. Material Amendments

The insurer's consent will probably be required in order to change material terms of the deal. Debt coverage will probably permit no material amendments to the underlying financing documents without the insurer's consent. For instance, MIGA's form guarantee for project lenders provides:

> The Loan Agreement, any underlying promissory notes, and any other agreements evidencing the Guaranteed Loan may not be modified or amended without obtaining MIGA's prior written consent, which consent shall not be unreasonably withheld.
>
> A less restrictive version would only restrict amendments to the timing or amounts of insured scheduled payments or to the interest rate. Since, however, as a practical matter, a restructuring is almost certainly going to affect the dates and amounts of payments, the political risk insurance provider's consent will, with a similar degree of certainty, be required.

A special note is in order for insured bond financings. A popular restructuring technique has been to issue replacement securities reflecting the restructured terms. Regardless of their terms, these are likely to constitute entirely new securities not contemplated or covered by the insurance policy. Thus, the scope of the insurer's ability to refuse coverage of the replacement bonds is likely to be greater than in the case of a simply rescheduled bank loan. This is an issue probably best addressed up front in negotiating the terms of the coverage. Discussed at that point, it is likely to be achievable to provide that the insured securities will include any replacement securities whose scheduled payments do not exceed those of the original securities, thus reducing the consent problem to the same issues that have already been identified for bank loans.

3. Disclosure

Often both the existence and terms of political risk insurance coverage is required to be kept confidential. Depending on the parties that become involved in a loan restructuring, the insurer's consent may be required in order to disclose to an interested party the existence of the coverage. For instance, some MIGA lender's contracts provide that MIGA can terminate its guarantee if:

> the [project lender] discloses without MIGA's prior written authorization the terms and conditions of the [Insurance] Contract to any third party other than the lawyers, auditors, accountants and government regulators in the country of the [project lender]. For the purpose of this Subsection, disclosure to government regulators of the Host Country shall require MIGA's prior consent, such consent not to be unreasonably withheld.

Note here that, though a reasonableness standard applies to MIGA's disclosures to host country government regulators, an absolute right to refuse disclosure, on pain of termination of the coverage, applies with respect to, for instance, interested commercial parties such as new debt or equity investors.

4. Being Reasonable

It is clear that the crux of dealing with political risk insurance in a project loan restructuring is likely to revolve around the insurer's consent — not to be unreasonably withheld. Consequently, the obvious question is: under what circumstances could an insurer (reasonably) withhold consent?

Clearly the insurer can reasonably refuse consent if its business interests are adversely affected by the restructuring. The relevant interests of a political risk insurer include the likelihood and magnitude of claims. Either — or both — of these might well be affected by a loan restructuring.

How could a loan restructuring increase the likelihood that the political circumstances covered by the policy might arise? Such circumstances develop over time. If the term of political risk coverage is / continued page 56

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extended, then the risk of a covered event occurring necessarily increases. That increase may be slight, but an extension in the maturity date of an insured loan would likely be seen by a political risk insurer as increasing the risk of a claim occurring.

Instead of extending a loan's maturity, the rescheduling agreement might call for past due or current principal payments to be distributed over future scheduled payments, without extending the final maturity date. This should have no impact on the likelihood of a claim, but it could affect the size of a claim. If an event, such as currency inconvertibility, were to prevent a scheduled debt service payment from being made, the size of the missed payment would have been increased by the rescheduling. Similarly, a negotiated increase in the interest rate to reflect the increased risk now associated with the troubled loan would increase the size of scheduled debt service payments and thus adversely affect the insurer's exposure.

In any of these circumstances — extended maturity or increased scheduled payments — the insurer would be within its legal rights in refusing consent.

Consenting to a rescheduling could also be seen to increase the likelihood of a claim if the political risk profile of the country has deteriorated since the policy had been priced and issued. If, for instance, the restructuring occurs in the context of a broad, macro-economic disruption (as in Indonesia or Argentina), the insurer might well be concerned that such unsettled circumstances could breed political as well as commercial risks. Issuing the consent would result in the insurer having an ongoing exposure that is riskier than it would have knowingly accepted at the inception of the transaction. Certainly this is a circumstance in which the insurer would welcome being released from the policy and might be tempted to withhold its consent in order to encourage cancellation of the coverage. Consents may, consequently, be most difficult to obtain when they are most needed.

Whether the insurer in this circumstance could "reasonably" withhold its consent to the restructuring is not clear under New York law. On one hand, the insurer has a rational business interest in withholding consent if that might lead to avoiding unwelcome risks. On the other, possible deterioration in the political environment is exactly the risk that the insurer assumed upon issuing the policy. However disconcerting the current circumstances, issuing the consent does not worsen its situation relative to the circumstances in which it agreed to be at risk under the policy. Consequently, refusing the consent as an exit strategy from deteriorating circumstances might not be "reasonable," regardless of how attractive it might appear at the time to the insurer. Rather, it would be exploiting the dire circumstance of the borrower and its lenders as a basis for improving the insurer's own position.

In a possibly less sympathetic variation of these circumstances, the restructuring does not directly adversely affect the insurer relative to the circumstance in which it finds itself at the time the need for the restructuring arises. Nonetheless, the right to withhold consent creates an opportunity to improve its business situation, as by collecting a fee, raising the premium rate, adjusting the terms of the coverage to its advantage, or inducing cancellation of the coverage.

Using one's consent right to gain an unrelated advantage where the point requiring consent poses no adverse consequence to the consenter is less likely to be found "reasonable" as a matter of New York law.

While case law on these issues is thin, and substantial legal arguments could be marshaled on either side, as a practical matter insurers are likely to feel substantially constrained in their ability to withhold consent to a restructuring. Nonetheless, they are unlikely to be sidelined during the restructuring process. The likelihood that a project loan restructuring does not involve some element of principal rescheduling, maturity extension or interest rate increase — to which the insurer could clearly refuse consent — is slight.

What happens to the deal if the insurer's consent is required and could be (reasonably) refused? Lenders have three options. One is to terminate the coverage (although some coverages may not be cancelable). Another is to compensate the insurer with increased premium or adjustments in the terms of the coverage (such as enhanced exclusions) so as to gain the necessary consent. Another option is to structure the rescheduling around the insurance policy terms so as to obviate the need for the insurer's consent or, equivalently, to make it unreasonable for the insurer not to give its consent.

With respect to the third option, the rescheduled loan payments might be separated into two streams. One would correspond to the original, insured scheduled payments. The second would comprise any additional principal or interest coming due within the original term of the loan as well as any payments due after the original maturity date. This second payment stream would be uninsured or, alternatively, separate coverage might be sought for it.

Note that this second stream would trigger any provisions in the insurance policy dealing with the allocation of payments between the insured loan and any uninsured debt of the borrower, especially if held by the insured lenders. A likely adequate solution from the insurer's perspective would be to subordinate each payment under the second stream to timely payment of the related payment under the insured stream. There might also be room to negotiate more balanced terms with the insurer without undermining the reasonableness of its consent to the restructuring.

With respect to the second option, an interesting question arises in the circumstance that the insurer could withhold consent because of an extended maturity or larger scheduled payments, but the lenders offer to pay an increased premium to compensate for that enhanced risk. Is it now unreasonable for the lender to refuse consent? Is it unreasonable for the lender to condition its consent on a substantial increase in its premium? The answer is likely to be fact-specific and depend on the eye of the arbitrator.

With respect to the first option, cancellation of the coverage, a potentially awkward circumstance could easily arise: the insurance might not be cancelable. Coverage that cannot be cancelled, at least so long as the insured continues to hold an insurable interest in the insured notes, shares, etc. is quite common. For instance, MIGA's lender coverage is typically cancelable only after three years unless the project is earlier liquidated or the borrower is bankrupt or the lender no longer holds the insured notes.

The terms regarding cancellation of coverage tend to relate closely to how premiums are determined and paid. A broad range of practice exists within the political risk insurance industry with respect to such premium-related terms.

On one end of the spectrum is OPIC's pay-as-you-go approach, where premiums are paid semi-annually. The policy can be canceled for any period for which a premium has not been paid. Further, to the extent that the insured loses the benefit of the policy because, for instance, the insured loan has been repaid or the insured lender ceases to be eligible for OPIC coverage, then OPIC will refund a corresponding portion of the premium.

At the other extreme are "political-only guarantees" such as those issued by the Export-Import Bank of the United States. The political-only guarantee fee is calculated for the scheduled life of the guaranteed loan and is charged up front (though it may be paid over time together with loan payments). The full fee is due even if the loan is prepaid or if, for some reason, the guarantee is cancelled.

Commercial insurer practices tend to lie between these extremes with substantial, negotiable variation. The leading concept is that the insurer agrees up front to accept certain risks that may arise over an agreed time period. Having accepted that risk up front, the insurer has fully earned its fee. From that perspective (akin to the Ex-Im Bank approach), the premium should be fully due and payable even if the insured subsequently decides to cancel the coverage. In practice, it is often negotiated that the coverage will be non-cancelable (or at least that the premium will be due notwithstanding cancellation) for a certain number of years beyond which the premium will convert to the OPIC pay-as-you-go model.

If a rescheduling arises while coverage is non-cancelable, and the insurer is within its rights to refuse consent to the proposed terms of a needed rescheduling, can the insurer block the restructuring because the coverage is non-cancelable, even if the lenders are willing to forego the coverage? Clearly not. Rather, the continued payment of the insurance premium becomes a cost-of-doing-business under the restructured loan. It would be a cost with dubious benefit, however, because, if the restructuring were to proceed without the insurer's consent, the insurer would have substantial grounds for refusing to pay any subsequent claim.

This could quickly spawn an awkward, legally untidy situation. Imagine that the lenders conclude a project loan restructuring to which the insurer refuses to consent. The lenders continue to pay the insurance premium as it comes due. Then a claim arises. The lenders' likely position will be that the insurer's failure to consent to the restructuring was unreasonable. That, of course, will not be the insurer's position given its enhanced risk stemming from the terms of the restructuring. The insurer might well */ continued page 58*

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refuse to pay that claim (at least to the extent that the amount claimed varies from the originally scheduled payment) on the grounds that it arose from a restructured loan as to which it never agreed to have any obligation.

The insurer might argue that it accepted a certain basket of risks at closing, and that the premium payments simply represent installments toward payment in full of a fee that was earned by the insurer up front for its acceptance of those risks. The rescheduling took the loan out of the scope of the accepted risks. The insurer should not be harmed by the lenders' unilateral decision to forego the terms to which the insurer had originally committed under the policy and which it continued to be willing to perform.

The insurer might, however, be concerned that an arbitrator might view its continued acceptance of premiums as tacit consent to the rescheduling. The arbitrator might view dimly the insurer's insistence that it was due the premiums even though, as a practical matter, it considered itself no longer at risk under the policy, at least to the extent that the restructuring affected the scheduled payments.

This situation is legally untidy because a host of legal, contractual and equitable arguments could be marshaled for each side in this dispute. Such a "ticking time bomb" in the form of a potential dispute would offer both sides added incentive to achieve agreement on the consent in order to avoid embedding such a potential dispute in the relationship.

Among the interests served by achieving agreement on the insurer's consent is the insurer's own interest in being regarded in the market as a reasonable business partner. The parties may have other pending transactions with each other, plus an expectation of future deals. This tempers any inclination to behave in an unnecessarily difficult fashion. Though the political risk provider side of the market is small, some opportunity still exists to vote with one's feet. Further, again because of the size of the market, reputations can be established, or tarnished, quickly.

There are further incentives to achieve agreement on the insurer's consent. Lenders to a troubled project will consider their options. Though the project's credit is impaired, and most might see the causes simply as commercial, some creative, if misguided, minds might try to attribute the project's demise to actions covered by (a stretch of) the insurance policy. In such a context, where loan defaults could give rise to a claim, the insurer will have added incentive to cooperate with a proposed loan restructuring if doing so avoids a claim being filed.

No political risk insurer admits to refusing to consent to a restructured loan, although two said coverage was terminated.

Even non-meritorious claims are a problem for insurers. Though insurers are far less likely to pay such claims, or to be required by arbitrators to pay such claims, claim denials always bring a reputational risk that one would naturally prefer to avoid. Insurers will work to have such claims withdrawn rather than to have to deny them. This reputational concern may well give an insurer further incentive to consent to a loan restructuring, notwithstanding a marginal adverse impact on the insurer's risk profile, because the insurer may well see an advantage in encouraging the lenders to move in a direction — maintaining the loans — that avoids even an unmeritorious claim.

Better, of course, would be to avoid the need for seeking and granting consents. A partial solution to the rescheduling problem can be achieved by negotiating up front a degree of flexibility. Some debt coverage contracts incorporate the concept of a "permissive rescheduling" pursuant to which the term "scheduled payments" is extended to include not only the original schedule but also a replacement schedule that lies within agreed parameters.

Impact of Equity Coverage

The discussion so far has focused on debt rather than equity coverage. Equity insurance is probably less likely to be a central issue in a loan restructuring. It could, however, be relevant.

The proceeds of the equity insurance policy are often pledged as part of the collateral package for the project loans. The terms of the restructuring should take care not to violate the terms of the equity policies in any way that might void the policies or provide a defense to payment of a claim. An example would be the eligibility requirements for OPIC and MIGA. Imagine, for instance, that an English bank had provided loans to a US-owned project in which the equity investment was insured by OPIC. The equity investor pledged to the bank both the project shares and the proceeds of the OPIC policy. Upon loan default, the bank forecloses on, and takes ownership of, those shares. The OPIC policy would become worthless for want of an eligible insured investor.

More generally, if the shares pledged as part of the collateral package are insured against political risks, then, just as attracting fresh lenders might be facilitated if the new lender can benefit from the existing coverage, so too the share collateral may be more valuable if coverage will follow transfer of the shares. Typically, it will not. Aside from the problem of finding an eligible investor, some coverage specifically restricts transference of insured shares without the insurer's consent. MIGA actually goes further and requires its prior written consent — without any comment as to reasonableness — prior to the transfer of any shares by the insured shareholder, whether or not the transferred shares are themselves insured.

Also, the equity insurer may have the right to cancel its coverage in the event of the project company's bankruptcy. Consequently, should a restructuring contemplate a prepackaged bankruptcy in which the equity policy is to be among the surviving assets, the insurer's consent would be required. Otherwise, it could simply terminate the coverage.

A number of lenders complained in Argentine restructurings, that sponsor access to equity insurance distorted the behavior of project sponsors who were inclined to rely on recovery from their insurer rather than to fight to salvage the project for the benefit of, among others, the project lenders. This complaint is too common to dismiss, but it is somewhat surprising. If the sponsors turn to their insurers, then the insurers who step into their shoes should have the same incentive to salvage the project as an uninsured sponsor would have had. The problem may reflect the fact that international law (both customary international law and investment-related treaties) provides rights to project sponsors — *i.e.*, equity investors in projects — against offending governments that are not as clearly available to debt investors.

The lesson to draw is probably not for lenders to discourage equity investors from insuring their investments (in particular because the project sponsors will enjoy those international law rights whether or not they are insured) but rather for lenders to press for the establishment of equivalent rights against misbehaving governments. That, however, is a topic for another day.

The Real World

Collecting empirical data on political risk insurance in restructurings is difficult. Often the very existence of such insurance is confidential. Further, the negotiated terms on which an insurer bases its consent to a restructuring are unlikely to be publicized. Consequently, this article reflects a large degree of supposition, plus theoretical inference from the terms of political risk contracts and programs, all leavened with a dose of anecdotal experience.

To test the instructions set out in this article I undertook a small, unscientific survey of political risk insurance providers. I approached representatives of a half dozen different political risk insurers on a not-for-attribution basis. All but one was able to confirm that his or her organization had issued insurance on project loans that subsequently required restructuring for credit reasons. All of those five indicated that they had in fact consented to those restructurings. None admitted to refusing to consent to any restructured loan, though two mentioned instances in which coverage was terminated in connection with the restructuring.

Those minimalist survey results appear to support the hypothesis that restructuring subject to the consent of the insurer, "such consent not to be unreasonably withheld," appears in business practice to offer a workable standard for lenders and insurers, one not likely to stand in the way of fixing transactions that have broken. This is true notwithstanding a fair degree of legal uncertainty as to what, when push comes to shove, that standard actually means. ◎

Environmental Update

Kyoto Protocol

More than seven years after the Kyoto protocol on global warming was written in December 1997, the treaty will finally take effect. Russian President Vladimir Putin signed the treaty in early November. It will enter into force on February 16, 2005.

US companies with power plants, factories or other industrial facilities in most of Europe, Japan and Canada will now have to take steps to limit carbon dioxide, or CO_2, emissions from their plants. Emissions will have to be reduced during the first compliance period from 2008 to 2012.

Thirty three of the so-called "Annex I" industrialized nations that signed the global warming treaty have now ratified the protocol. These 33 countries will now be required to meet reduction targets ranging from 5 to 8% below their 1990 greenhouse gas emission levels. The United States has rejected the Kyoto protocol on the grounds that dramatic reductions in greenhouse gas emissions would harm the US economy.

The Kyoto protocol had to be ratified by 55 or more countries whose combined CO_2 emissions levels represent at least 55% of the CO_2 emissions from the Annex I countries in 1990 before the treaty could take effect. As of November 25, 129 nations have now ratified the treaty accounting for 61.6% of the 1990 CO_2 emissions. The United States accounts for approximately 36% of the 1990 CO_2 emissions from industrialized countries.

In related news, Kyoto protocol signatory countries are scheduled to meet in Buenos Aires in December at the "Tenth Conference of the Parties to the United Nations Framework Convention on Climate Change." Discussions at the 10th conference are expected to focus on climate change mitigation policies and their impacts and various implementation issues now that the Kyoto protocol has received the necessary approvals.

Several European countries have already moved aggressively toward implementing the protocol emission trading programs. Russia's ratification of the global warming treaty is expected to jump start an international financial market for trading in greenhouse gas reduction credits. On January 1, 2005, the European Union emission trading program officially gets underway. The European Union countries have agreed to cap CO_2 emissions covering approximately 12,000 industrial facilities in Europe. Emission allowance allocations will be granted pursuant to national allocation plans that have already been adopted by each of the member countries. Allowances will be allocated for the first trading period of 2005 to 2007.

Under the national allocation plans, industries such as power generation, iron, steel, and pulp and paper, will be allocated tradable allowances worth one ton of CO_2 each. Companies that do not have a sufficient allocation of CO_2 allowances will need to buy additional allowances on the open market or reduce their emissions. Conversely, companies with a surplus of CO_2 allowances may sell them on the open market.

Other Kyoto protocol mechanisms for generating tradable greenhouse gas emission reductions involve "joint implementation" projects in which an Annex I country or company in an Annex I country can receive "emissions reductions units" or ERUs generated by emission reduction projects in another Annex I country. ERUs can be sold or otherwise transferred among companies in Annex I countries. In addition, the treaty establishes a mechanism where Annex I parties can create "certified emissions reductions" or CERs through the development of projects that reduce net emissions of greenhouse gases in non-Annex I countries. Annex I parties, including the governments as well as private companies, can assist in financing these projects and purchase the resulting CERs as a means of reducing their own emission reduction requirements.

The Netherlands, for example, has recently entered into an agreement with the International Finance Corporation to create a "Netherlands European carbon facility" that will acquire ERUs developed through joint implementation projects in Europe and in other Annex I countries. Numerous other greenhouse gas emission reduction projects between Annex I countries and between Annex I and non-Annex I countries are reportedly in the works.

Bush Agenda

The election of President Bush to a second term and larger Republican majorities in Congress are expected to give new momentum to the president's "clear skies initiative." It calls for significant reductions in nitrogen oxide, or NO_X, sulfur dioxide, or SO_2, and mercury from power plants. The initiative stalled in the last Congress. Both administration officials and the committee chairmen in Congress say that enactment of the Clear Skies Act will be a top legislative priority for 2005.

The Clear Skies Act would force substantial reductions in NO_X, SO_2, and mercury emissions from power plants by setting nationwide emission caps in a two-phase process. The Senate version of the Clear Skies Act would set nationwide caps of 2.1 million tons of NO_X in 2008, 4.5 million tons of SO_2 in 2010, and 34 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. The President's plan would achieve the reduction targets through a mandatory "cap-and-trade" emission allocation program for the three pollutants similar to the SO_2 allowance trading under the federal acid rain program. The Clear Skies Act does not provide for any cuts in CO_2 emissions from power plants.

It is still debatable whether the president has the votes to put his bill through Congress. Republicans are expected to have a 10 to 8 majority in the key Senate Environment Committee, but Senator Lincoln Chafee (R-Rhode Island) has often sided with Democrats on environmental issues. The Bush administration is expected to pursue a dual track of trying to put its Clear Skies Act through Congress while at the same time having the Environmental Protection Agency issue regulations that would achieve many of the same objectives. EPA is expected to finalize its proposed "clean air interstate rule" (formerly called the "interstate air quality rule") by the end of the year. The clean air interstate rule will require power plants in 29 eastern, midwestern and southern states and the District of Columbia to reduce NO_X and SO_2 emissions from power plants by 2015. EPA is also planning on finalizing its clean air mercury rule (formerly called the "utility mercury reductions rule") that will require cuts in mercury and nickel emissions from coal and oil-fired power plants. EPA is under a court order to issue a rule to reduce mercury emissions from coal-fired power plants by March 15, 2005.

Some industry sources have asserted that going forward with the clean air interstate rule will reduce the desire of some lawmakers to push for enactment of the Clear Skies Act. EPA officials do not view pursuing parallel legislative and regulatory tracks as counterproductive, and instead point out that while a legislative approach is clearly the Bush administration's preference, the clean air interstate rule will keep the power industry on track to achieving significant NO_X and SO_2 emission reductions by 2015.

The Clear Skies Act would apply to all fossil fuel-fired power plants in the United States that meet the applicability thresholds. Conversely, the clean air interstate rule is limited to certain fossil fuel-fired power plants in 29 states and the District of Columbia, and the final rule is expected to be challenged in the courts by environmental groups. A legal challenge may delay implementation of the Phase I reduction targets under the clean air interstate rule.

Other Bush administration legislative priorities for the next Congress that convenes in January include enacting a comprehensive energy bill with a provision authorizing oil exploration and drilling in the Arctic National Wildlife Refuge or ANWR, a chemical plant security bill, and legislation to cap damages and set standards for awards in asbestos cases. The Bush administration wants to try again to put Alaskan oil drilling though Congress now that it has a larger Republican majority. The House passed an energy bill last year with an ANWR provision and a similar measure was narrowly defeated in the Senate last year by a margin of 52 to 48.

Cooling Water

In November, EPA issued a proposed "Phase III" rule that imposes new requirements on cooling water intake structures for manufacturing and industrial facilities that are not covered under the Phase II rule it issued on July 9, 2004. The Phase II rule covered large existing power plants. Phase I of the cooling water regulations were issued on June 19, 2003 and address new facilities. The proposed Phase III cooling water regulations were issued under section 316(b) of the Clean Water Act, which requires EPA to develop rules requiring that the "best technology available" be used to protect aquatic organisms from being impinged or pinned against water intake screens or drawn into the cooling water system.

The Phase III regulations could require significant upgrades to existing cooling water intake systems at affected plants, particularly at plants that withdraw water from lakes or rivers with sensitive / continued page 62

aquatic habitats and species. The rule is expected to cover larger chemical plants, pulp and paper mills, iron and steel facilities and other large industrial plants with significant water use requirements.

EPA proposed three options for Phase III facilities. The most stringent option would apply to industrial facilities that have a total design intake structure capable of withdrawing at least 50 million gallons a day from any waters in the US. The second option would cover industrial facilities with a total design intake structure capable of removing at least 200 million gallons a day from any water body. The third option would apply to a more limited subset of eligible facilities, namely industrial facilities with a total design intake structure capable of removing at least 100 million gallons a day from an ocean, estuary, tidal river or one of the Great Lakes. Under all three options, the facility must use at least 25% of the water for cooling purposes to be covered by the rule. Manufacturing facilities with intake structures below these thresholds would continue to be subject to section 316(b) requirements on a case-by-case basis.

The proposed technology performance standards are substantially similar to the standards in the Phase II rule for large power plants. The requirements are based on the type of water body from which the water is withdrawn and, in general, facilities will need to reduce impingement mortality by 80 to 95% and reduce entrainment of aquatic organisms by 60 to 90% from uncontrolled levels. The proposed rule identifies several compliance alternatives, including using existing construction and design technologies to reduce impingement and entrainment of aquatic organisms (including reducing flow velocity or implementing a closed-cycle recirculating cooling system), selecting additional fish protection technologies (such as screens with fish return systems), and using restoration measures (such as restocking affected fish or creating alternative habitats).

The new requirements will be implemented through the renewal of existing National Pollutant Discharge Elimination System, or NPDES, permits. The comment period on the proposed Phase III rule is open until March 24, 2005, and the rule is expected to be finalized later in 2005.

US companies must take steps to reduce carbon dioxide emissions in as many as 33 countries after the Kyoto treaty enters into force in February.

Mercury

In early December, EPA published a notice in the *Federal Register* inviting the public to submit comments on new data and information it has received in connection with the clean air mercury rule (formerly called the "utility mercury reductions rule"). EPA is under a court order to issue the final rule, which would regulate mercury and nickel emissions from existing and new coal- and oil-fired electric power plants, by March 15, 2005.

The agency said in the notice that it received more than 680,000 comments from the public. Several of the submittals included modeling analyses, and the notice summarizes several of those analyses. EPA has preliminarily revised its approach to analyzing the benefits of reducing mercury emissions from power plants based on the comments it received, and it is inviting further comment on that revised approach.

EPA is under a 1998 court-approved settlement agreement with the Natural Resources Defense Council to develop mercury standards for coal-fired plants. In January 2004, EPA published two alternative approaches for regulating mercury and nickel emissions from coal- and oil-fired power plants. The first alternative closely tracks the administration's "clear skies initiative" with respect to mercury reduction measures, and it proposes a "cap-and-trade" rule to regulate mercury from existing coal-fired plants. This alternative would implement a 34-ton first phase cap on mercury emissions commencing in 2010 followed by a 15-ton cap starting in 2018. Mercury allowances would be issued to coal-fired plants based on a unit's share of the total heat input from existing coal units multiplied by an adjustment factor depending on the type of coal: one for bituminous, 1.25 for sub-bituminous, and three for lignite coals. Mercury is generally more difficult to remove from lignite coals than from bituminous coals.

The second alternative takes a traditional command-and-control approach to regulating mercury and nickel under section 112 of the Clean Air Act, and it proposes specific emission limitations based on so-called "maximum achievable control technology" or MACT. Under this approach, the MACT standards would have to be achieved within three years after the final rule is issued. EPA projects that mercury emissions would be reduced from the current level of about 49 tons to 34 tons through implementation of the proposed mercury MACT standards.

EPA prefers using the more flexible "cap-and-trade" approach. This alternative has been met with strong resistance from the environmental community. EPA will be accepting comments on the notice of data availability until January 3, 2005. It must issue the final clean air mercury rule by March 15, 2005, and it is a near certainty that the final rule will be challenged in court.

In related news, the Department of Justice has asked a federal district court to dismiss a lawsuit filed by three environmental groups in an effort to force EPA to issue final MACT standards for new and existing coal- and oil-fired power plants. The lawsuit appears aimed at pressuring EPA into issuing a final clean air mercury rule that is more stringent than the current alternatives. The lawsuit highlights the intense scrutiny that EPA's proposed mercury rule is facing.

The environmental groups alleged that the proposed clean air mercury rule is inadequate and fails to comply with the section 112 MACT-setting standards of the Clean Air Act. In its motion to dismiss, the US government takes the position that it does not have to promulgate MACT standards if it acts on or before March 15, 2005 to remove coal- and oil-fired power plants from the list of sources subject to the section 112 standard-setting requirements. In developing a final mercury "cap-and-trade" rule, EPA would need to first remove coal- and oil-fired power plants from the section 112 category list. A decision in the case is expected in early 2005.

Colorado RPS

Colorado became the first state to pass a renewable portfolio standard via a statewide vote. On November 2, 53% of Colorado voters supported the adoption of Amendment 37, which will require Colorado's seven largest utilities to supply a certain percentage of their retail electricity sales from renewable energy sources. Starting in 2007, Colorado utilities must meet a 3% target, which will increase to 10% by 2010.

Eighteen states now require that a portion of the electricity supplied in the state be generated from renewable resources. Earlier this year, Hawaii, Maryland, New York, New Mexico and Rhode Island also adopted RPS requirements, and several state legislatures are expected to enact additional RPS programs in 2005.

Colorado has yet to fill in many of the details of its new program. The state program is expected to apply to renewable energy plants using wind, hydroelectric, biomass, geothermal and solar energy. The Colorado ballot initiative may signal a growing interest in using voter referendums as a mechanism for putting RPS programs in place. The downside of such voter initiatives is that inevitably the ballot language provides few details on the program is supposed to work.

Brief Updates

In mid-October, a New York trial court upheld the emergency action of the New York State Department of Environmental Conservation to keep its NO_X and SO_2 emissions reduction programs on track. The rules call for significant reductions in NO_X and SO_2 emissions from power plants to levels that are well below current federal requirements. The new NO_X rule will implement a statewide NO_X trading program with a program-wide cap for NO_X emissions during the non-ozone season of October 1 to April 30. NO_X emissions are already controlled statewide during the summer ozone season months. The NOx reduction requirements became effective immediately. The SO_2 rule requires SO_2 emissions to be reduced by 50% below current federal acid rain program levels starting on January 1, 2005, with full implementation completed by January 1, 2008. / continued page 64

Environmental Update

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The American Chemistry Council recently announced that its member companies would initiate a voluntary greenhouse gas emission reporting system to track progress in meeting the Bush administration's voluntary greenhouse gas emission reduction target. The administration has set a goal of achieving an 18% reduction in the intensity of greenhouse gas emissions by tying the reductions to the gross domestic product. The American Chemistry Council has set an industry goal of achieving an 18% intensity reduction by 2010.

In October, the US Supreme Court heard oral arguments in *Cooper Industries, Inc. v. Aviall Services, Inc.*, a case on appeal from an appeals court that held that private Superfund cost-sharing actions may be brought without having to wait for the federal government to issue a cleanup or consent order. The US solicitor general takes the position that a government enforcement order is a prerequisite to seeking contribution from other private parties. A decision in favor of the US government's position would require that the US Environmental Protection Agency file an enforcement action before one private party can seek reimbursement for a share of Superfund cleanup costs from other private parties. A decision is expected in late 2004 or early 2005.

In November, environmental groups filed a petition with the EPA administrator requesting reconsideration of a final rule regulating air toxic emissions from industrial and commercial boilers. Under the rule, new MACT emission standards to control carbon monoxide, hydrogen chloride, mercury and particulate matter will apply to certain large new and existing boilers. The rule includes a controversial "risk-based" exemption for certain units that present a low risk to human health. The environmental groups' petition argues that EPA lacks legal authority to establish case-by-case exemptions from MACT requirements. A decision on the petition is not expected until 2005.

New Jersey has adopted stringent mercury emission reduction requirements that apply to coal-fired plants, incinerators, and iron and steel smelters in the state. The New Jersey regulations set alternative compliance mechanisms for the coal-fired power plants in the state. The plants must generally reduce current levels of mercury by 90% by the end of 2007. Alternatively, a coal-fired power plant may opt to meet the 90%-reduction rate by 2012, provided the plant also makes significant reductions in NO_X, SO_2 and fine particulate emissions. The final regulations will be published in the *New Jersey Register* in early December.

In October, the US government filed a response brief in *International Center for Technology Assessment v. Whitman*, a case filed in the US appeals court in Washington, D.C. The plaintiffs in the case want the US Environmental Protection Agency to regulate motor vehicle emissions of CO_2 and other greenhouse gases. The US government is arguing in the brief that it lacks authority to regulate greenhouse gases. A decision by the court for the plaintiffs could have far-reaching implications. A decision in the case is not expected until 2005. ◎

— contributed by Roy Belden in New York

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