CHADBOURNE
& PARKE LLP

PROJECT FINANCE

NewsWire

October 2002

Potential Effects of Invading Iraq

by Keith Martin, in Washington

Chadbourne surveyed power company executives, bankers and consultants in late September about what effects they foresee on the project finance market if the United States invades Iraq.

Many said the effects depend on how long the war lasts and see little effect if the war is of short duration. James Schretter, president of Beacon Energy, a gas consultancy, said perceptions are probably more important than reality. "If the war is over quickly," Schretter said, "the impact will be minimal. But if the war — or the perception that a war is still in the offing — drags on, then it may depress the economy and have negative consequences for asset holders who are already experiencing tough times."

A long prelude to conflict is potentially more disruptive than the war itself since people may place plans on hold pending the outbreak of hostilities.

Oil Prices

In the last Persian Gulf war, oil more than doubled in price immediately after Iraq invaded Kuwait in August 1990 — from $15 to $33 a barrel — but then returned almost as quickly to pre-war levels by the end of the Desert Storm campaign in February 1991.

A consensus has taken hold in the press in both the United States and Britain that a change in government in Iraq would be good for world oil markets. */ continued page 2*

IN OTHER NEWS

TURKEY suggested that some private power projects will have to renegotiate the pricing, term and guarantee provisions in their power sales contracts.

Turkey is in the process of deregulating its electricity market. Companies engaged in the generation, transmission or distribution of power are required to apply for new licenses to operate. Regulations implementing the new license requirement were issued in early August.

Remarks by Yusuf Gunay, chairman of the agency that administers the licenses, in September appear to indicate that the */ continued page 3*

IN THIS ISSUE

Iraq

continued from page 1

Iraq is potentially a far more significant producer of oil than it contributes currently to the market. Iraq has averaged 1.18 million barrels a day of oil output so far this year, plus another 200,000 to 300,000 barrels a day of illegal output, according to the US Department of Energy. Iraqi output of 900,000 barrels a day in August was down 1.2 million barrels from production the year before. Iraq has the second largest known oil reserves of any country after Saudi Arabia. Iraqi reserves are 112.5 billion barrels. Saudi reserves are 261.8 billion. The other top 10 producers, in terms of known reserves are, in order: the United Arab Emirates, Kuwait, Iran, Venezuela, Russia, the United States, Libya and Mexico. US reserves are 30.4 billion barrels.

There is disagreement among experts about whether the price of oil already reflects a war premium. Spot oil prices had risen 15% by mid-September compared to last June. But some experts say this is explained by a 2% fall in supply and a 1% increase in demand during the same period. David Wheeler, an oil industry analyst at J.P. Morgan, told the *New York Times* that he does not believe war with Iraq would cause much of an increase in oil prices because the odds are "very, very long" that Saudi Arabia would fail to increase output to make up for any shortfall in supply caused by a drop in production in the war zone. The Saudis have the capacity to increase output by up to another four million barrels a day: almost four times current Iraqi output.

The oil price shocks were much greater when Iraq and Iran went to war in 1980. Oil shot up to close to $40 a barrel. However, the runup in oil prices began in early 1979 with a series of successive price increases put through by the Organization of the Petroleum Exporting Countries, or OPEC, and the oil price actually peaked just about the time that the fighting between Iraq and Iran began in September 1980. In the first 10 weeks after the war started, world oil inventories shrank about 30%. Fuel and power prices in 1980 rose 33% for natural gas, 23% for residual oil, 18% for electricity, and 9% for steam coal. The Saudis then flooded the market with inexpensive crude oil in 1981, causing a collapse in the OPEC pricing structure. In October 1981, all 13 OPEC countries agreed on a compromise benchmark price of $32 a barrel, but within two years, an oil glut had taken hold and prices continued to fall.

Oil prices peaked at the start of each of the last two Persian Gulf wars and fell as fighting spread.

Measured in current prices, a price of $40 a barrel for oil in 1980 is equivalent to about $83.70 a barrel today.

The average spot oil price for West Texas Intermediate was $28.40 a barrel in August.

The US Department of Energy estimates that each one million barrel-per-day reduction in oil supplies causes oil prices to increase by $3 to $5 a barrel and shaves 0.3% off the annual rate of US economic growth.

The Last Persian Gulf War

Economists are still debating whether the Desert Storm campaign in 1991 helped or hurt the US economy. World War II is seen universally to have lifted the United States out of a decade-long depression. The United States was already in a recession by the time Iraq invaded Kuwait in August 1990. The recession had started in June. Many economists believe that it was prolonged by the war; the recession lasted nine months. Robert Hall, a Stanford economist and chairman of a committee of seven prominent economists that dates business cycles, said at the time that the initial contraction might never have evolved into a full-blown recession without the damage caused by the war. Hall blamed high oil prices for the contraction. Iraq invaded Kuwait in August and, although the United States began an immediate airlift of troops to Saudi Arabia, the US did not start bombing Baghdad until January 16, 1991 after it had lined up support in the international community and after the collapse of peace talks in Geneva between the American secretary of state, James Baker, and the Iraqi foreign minister, Tariq Aziz, aimed at inducing Iraq to withdraw from Kuwait.

One difference this time is the US could be forced to pay more of the cost. Estimates this time are that the effort will cost more than $100 billion. The US allies paid most of the cost the last time; indeed, according to some estimates, the US made a profit. The US office of management and budget estimated that the incremental cost of the war effort — or the amount the US had to pay above what it would have paid anyway in defense costs — was $15 billion. The gross cost was $61 billion. (The gross cost includes transfers from already budgeted military outlays to Gulf operations plus the estimated future costs of replacing equipment lost in the war.) US allies contributed $54 billion.

The biggest losers from any new invasion will almost certainly be the airlines. Surging prices for jet fuel dealt a crippling blow to the airlines after the last conflict. Passenger traffic was also down; traffic on trans-Atlantic routes dropped 50%. The airlines are already reeling from the dropoff in passengers after September 11.

Domestic Power Market

Many power company executives think the situation can only improve for them. "As it seems the whole industry is in the tank, how worse can the situation be?" asked Hezy Ram, an executive at Ormat and a former Israeli tank commander. "I mean, banks are not open to new business, everybody is scared of the refinancings coming due, and the rating agencies have only one mode of operation — down. So, what else can go wrong?" Eric McCartney, head of project finance at KBC Bank, a Belgian bank, said, "Things quite honestly are already such a mess that it would be natural to think that war with Iraq will only exacerbate our problems but, at this point, how worse can things really get?" A harried chief financial officer at a large US merchant power company said he has his hands full just trying to get banks to step up and provide for ordinary-course-of-business liquidity needs, leaving little time to think strategically. "When you're up to your eyes in alligators, it's hard to see beyond the swamp."

Higher energy prices could create isolated opportunities in places like New England that rely more heavily on oil for generating electricity. One power company official said, "A war could have a beneficial effect on merchant plants insofar as some new gas-fired power plants that seemed destined, at current price levels, to run very few hours might find they can clear the market because older oil-fired units will not be able to compete." However, he compared / continued page 4

IN OTHER NEWS

government will require changes in certain contract terms for private power projects as a condition to issuing the projects licenses to operate. The changes will be required in contracts to sell power from private projects that were built using one of three ownership models. The three models are TOR for "transfer of operating rights," BO for "build-operate," and BOT for "build-operate-transfer." Companies with existing projects — other than those under the TOR model — have until April 3, 2003 to apply for a license.

THE US DEPRECIATION BONUS rules remain in flux.

Congress authorized a 30% "depreciation bonus" last March as an inducement to companies to invest in new equipment during a window period that runs from September 11, 2001 through 2004 or 2005, depending on the equipment. Most power projects have until 2005 to be completed. The bonus can reduce the cost of a project by as much as 5.39%. It can also be claimed on improvements to existing plants.

Congress is still tinkering with the rules. A package of "technical corrections" is expected to be introduced in October. It will probably not be enacted this year, but the tax-writing committees want to put US companies on notice what changes are anticipated. Some of the technical corrections under discussion would tighten eligibility for the bonus. While there had been discussion last August about the possibility that some of these rule changes might be prospective in effect — they would only apply to transactions after the technical corrections bill is introduced in October — that prospect appears now to have receded. The technical corrections are expected to apply retroactively to last March.

One issue in play is whether power plants are considered "self constructed." The depreciation bonus cannot / continued page 5

Iraq

continued from page 3

this to an "unexpected thunderstorm bringing just passing relief to a drought-stricken farmer."

Natural gas prices tend to follow oil prices. The US government is already predicting a 12% increase in demand for gas this winter because of forecasts for an unusually cold winter and because it is projecting that the US economy will have started to rebound by the third quarter of 2002. It estimates that the increase in demand will lead to a one-third increase in average gas prices at the wellhead to around $3.20 per thousand cubic feet. That is an 80¢ increase above the price last winter. For all of 2003, the average wellhead price is expected to be about $3.28 per thousand cubic feet compared to $2.80 last winter.

Electricity prices remain weak. David Costello, an economist at the US Department of Energy who studies linkages among oil, gas and electricity prices, said he does not expect higher oil and gas prices to lead to significantly higher electricity prices in the US. Overall, the increase in wholesale electricity prices will not be "as bad as the spikes generally experienced" on a hot summer day, Costello said. Another government energy economist said he expects the effect on electricity markets to be "negligible."

Many US power companies financed merchant plants with short-term debt; estimates are that at least $30 billion in such debt will come due in the next year or two. There is some nervousness among power companies that a war could add to bank jitters, particularly if there is a long period of uncertainty before a war is launched. The schedule announced by the United Nations weapons inspection team in late September envisioned negotiations over the protocols for inspections, to be followed by two months of sample testing to firm up procedures, to be followed by another four months of actual inspections. This schedule is unlikely to meet with US approval; the situation remained fluid as the *NewsWire* was going to press.

Almost without exception, bankers at US offices of European banks referred the question what effects they foresee from a war with Iraq to their European head offices. Most saw the most direct effect on banks that are lending directly to finance projects in the Middle East. They assume there will be a much smaller impact in other markets.

US executives based abroad or doing extensive business abroad remain worried about the safety of their employees in countries with large Moslem populations. One fund manager with operations in Africa said, "I believe it will make a difference whether the US goes it alone — in which case, the ramifications will be far worse against Americans and US companies, especially those with business in Moslem countries — or as part of a genuine consortium where, presumably the anger would be diffused and not all the blame would be directed toward the US." An American based in London said, "All will depend on how the war is executed and if there are any surprises. A nuclear or chemical bomb and all bets are off."

Legal Issues

A general counsel at a large US multinational company said he is spending time studying the company's insurance policies for potential gaps in coverage. Many insurance policies exclude losses caused by war. For example, conventional insurance policies in the London market typically exclude coverage for loss, damage or expense caused by "war or any hostile act by or against a belligerent power . . . [and] any terrorist or any person acting from a political motive."

Lawyers said that disruption to shipping, lack of insurance coverage, volatility in oil prices, and a continued weakness in the economy could lead to claims that contracts cannot be performed on schedule or even that parties should be released altogether from performance.

Bill Greason, a capital markets partner in the Chadbourne office in London, said that underwriting agreements to place shares or debt in the capital markets typically contain "market out" clauses that release the underwriter from performance if there is an outbreak of hostilities between the signing and closing of a deal. "They do not like doing this because they make no money, but if the financial markets are in disarray, the underwriter does not want to be left holding the stock or bonds," Greason said. However, he said that the outbreak of war would have to be coupled with some other event, like a major disruption to the market, before a market out clause could be invoked. Noam Ayali in Washington said that the debt offerings that are the least likely to be disrupted are ones where repayment is guaranteed by the US government through the Export-Import Bank or the Overseas Private Investment Corporation.

Chadbourne lawyers were divided about whether there could be significant "material adverse change" or *force* *majeure* claims in the near term as a result of the war. War has the potential to disrupt shipping and the production of goods. "A war could interfere with the shipment of equipment either because of the location of the project — for example, in the Gulf — the lack of available ships — perhaps because commercial vessels are being used to carry equipment needed for the war — or even because factories are being shifted to production of equipment needed by the military," Lynne Gedanken said from London.

Loan documents and acquisition agreements make it a condition to performance that there have been no "material adverse change" in circumstances. This is normally an ongoing covenant to each future draw on a loan. Material adverse change is "difficult to assert but may be possible if the outbreak of war directly affects the company in question — for example, the main manufacturing plant is located in a war zone," Bill Greason said.

Construction contracts and other agreements to supply goods or services have *force majeure* clauses allowing for delays in performance due to acts of God, war, weather and similar events outside the control of the parties. There does not have to be have been a formal declaration of war before these clauses can be invoked, said Denis Petkovic in London. "Whether war exists is usually a question of grim reality rather than a technical nicety." John Baecher in New York said "increased costs and delays in transportation or insurance and perhaps with respect to possible price increases or fuel shortages or embargoes" could result in *force majeure* claims under construction contracts. However, "many if not most, *force majeure* provisions only allow a party to claim *force majeure* as a result of a war if the war is in the country in which the project is located or sometimes if that country is a participant in that war," Lynne Gedanken said from London. "I suspect that whether parties can claim force majeure in the event of a war will be a source of dispute."

Fuel price increases have the potential to squeeze one or the other parties to power sales agreements. Few independent power companies in the US use oil to generate electricity. However, gas prices tend to move in the same direction as oil prices. Some offtake contracts pass through price increases. In those cases, the burden will be on power purchasers to find the extra money to cover the higher costs. Other contracts may not properly track fuel price changes. In those cases, the burden is on the power supplier. "Decreased net revenue associated with higher fuel and other / *continued page 6*

IN OTHER NEWS

be claimed on a project to which the taxpayer was committed before September 11 last year. A company is considered committed to a project it is self constructing, or building itself, once physical construction begins. It was committed to a project that it is "acquiring" from someone else once a binding contract is signed to acquire it. Most power projects are considered self constructed under a broad definition Congress adopted last March. However, Congressional staff are concerned that the definition is so broad that aircraft the airlines purchase from Boeing or Airbus are also self constructed. The technical corrections bill is expected to tighten the definition to knock out aircraft.

Another issue in play is whether someone who buys or invests in a project that is under construction can claim a bonus on the project if the current developer would not have qualified for one. The Joint Tax Committee staff favors letting a bonus be claimed on spending to complete the project after the new owner has purchased it, but not on the purchase price he paid to buy into the project. Most tax counsel believe the current statute allows a full bonus, including on the purchase price. This issue is still in play.

Meanwhile, the Internal Revenue Service is expected to issue guidance on depreciation bonus issues — probably in the form of questions and answers — by next June. The IRS has drawn up a list of possible questions to address. The power industry submitted 25 fact patterns for the IRS to discuss in the guidance. Chuck Ramsey, the IRS branch chief, said that some, but not all, of the 25 will be covered. Other guidance may come in a "blue book" that the Joint Tax Committee staff is writing for publication early next year.

The power industry has discussed with Congressional staff and / *continued page 7*

Iraq

continued from page 5

input prices will reduce coverage ratios and may trigger cash traps" in loan agreements, Lynne Gedanken said. Higher transportation costs due to problems with insurance cover or lack of ships are another cost that will fall differently on the parties depending on the contract terms in particular deals.

"The problem of insurance will re-emerge with a vengeance even more so than after the September 11 tragedy," said Noam Ayali in the Washington office. Ayali said he suspects that US and UK developers may want the cover of a multilateral agency when doing projects in developing countries where the US might be unpopular because of the war. He also expects the burden will fall on multilateral lending agencies and export credit agencies — rather than private insurers — to come up with creative new ways to address the risk of political violence. "This may lead to interesting developments in the agency products, risk allocation, and interaction with the private sector."

Other Effects

Two US tax credits — one for windpower and the other for landfill gas and synfuel projects — are linked to energy prices. One is a so-called section 29 credit of $1.083 an mmBtu for producing landfill gas or synthetic fuel from coal. If oil prices return to levels reached during the Arab oil embargo in the 1970's, then this credit would automatically phase out. However, the phaseout is tied to the average annual wellhead price for domestic crude oil in the United States. The average domestic oil price would have to reach $49.15 a barrel for an entire year before a phaseout would start.

The other credit is a so-called section 45 credit of 1.8¢ a kilowatt hour for generating electricity from wind. This credit could also phase out automatically, but the phaseout for it is tied to domestic electricity prices and not to oil.

One executive said he hoped, with the potential for renewed volatility in energy prices, that California officials might see the folly of moving so quickly to burn bridges to merchant power suppliers by tearing up contracts. The state signed long-term contracts to buy electricity last year during the period power was in short supply and then quickly regretted locking in electricity purchases when prices were at a peak.

Renewable energy companies hope that the reminder that oil supplies are uncertain might give an additional boost to renewable energy. However, *The Washington Post* reported on September 29 that the possibility of war with Iraq and disruption to oil supplies appears to have had no effect on the energy policy debate in Congress. Both houses of Congress have passed a national energy bill and are working to reconcile differences in the two versions before Congress adjourns for the year in early October. At this point, Gene Peters, chief lobbyist for the Electric Power Supply Association, said, the conferees will be happy just to have anything they can call an "energy bill" regardless of content. The Senate version of the energy bill would require US utilities to ensure that at least 10% of the electricity they supply is from renewable sources by 2020. However, the odds for this renewables mandate have not been affected by the talk of an Iraq conflict, Peters said.

Jack Greenwald, a former Chadbourne partner now practicing law in the Middle East with Greenwald & van de Kraats, reported from Dubai that it is business as usual — at least for now. "Our legal practice has been as busy as previous Augusts and Septembers, as business in Dubai tends to be driven more by Dubai events than by tensions elsewhere in the Middle East. The members of the American community here are not noticeably nervous or keeping their bags packed," he said, but an outbreak of war in the region would probably lead the US Navy to evacuate Westerners and their dependents.

The Giga-NOPR: Big Deal?

The US government published 600 pages of proposals at the end of July that the newspapers said could transform how electricity is produced and sold in the United States. The following are excerpts from a discussion that took place by phone in mid-September among a group of regulatory experts. The experts addressed whether the new proposals — called a "notice of proposed rulemaking," or "NOPR" — are as significant as the press claims and, if so, why and what is in them about which any well-informed CEO of a power company or banker lending to finance power projects should be aware. The speakers are Julie Simon, vice president for regulatory policy at *the Electric Power Supply Association, Vito Stagliano, vice president for transmission policy at Calpine Corporation, David Reich, senior manager, technical and legal analysis, at Mirant Corporation, Dr. Robert Weisenmiller, one of the leading experts on the California power market and a founder of MRW Associates, Inc. in Oakland, California, and two Chadbourne lawyers, Lynn Hargis, a former assistant general counsel of the Federal Energy Regulatory Commission for electric utility regulation, and John O'Sullivan, who held the same position as Hargis at FERC and was later chief advisory counsel to the commission. The moderator is Keith Martin.*

MR. MARTIN: *Global Power Report* said in an article on August 8th: "The Federal Energy Regulatory Commission has taken probably its most sweeping and profound action ever to define the electricity marketplace . . . ." An Energy Business Watch flyer for a seminar said the giga-NOPR will "profoundly transform the wholesale electricity markets."

Julie Simon, is the giga-NOPR really *that* significant, or is this an exaggeration?

MS. SIMON: Yes. It's a huge next step for the federal government to recognize the need for a single transmission tariff to ensure that all users of the transmission system take service under the same tariff conditions. From our perspective, representing the competitive power supply industry, inability to get access to the grid on equal terms with utilities has probably been the biggest impediment to workable competition in the industry. For FERC finally to recognize this and to take steps to remedy it I think is incredibly significant.

MR. MARTIN: Dave Reich, do you agree with that assessment?

MR. REICH: Definitely. I echo what Julie said. This is truly huge. Taking decisions about use of the grid away from the investor-owned utilities — requiring them to turn the grid over to an independent transmission provider — will go a very long way to complete open access for anybody who requests transmission service. It will do away with a lot of the discriminatory behavior that independent generators have had to put up with for the last few years.

MR. MARTIN: Vito Stagliano, isn't there more to the giga-NOPR than just more open transmission?

MR. STAGLIANO: Yes, though I view it as less earth-shaking perhaps than does the press. It is important to see it in context. FERC issued this new proposed rule in order to rectify its 10-year failure to address discrimination in the wholesale power market. It had issued */ continued page 8*

IN OTHER NEWS

the IRS whether turbines ordered before September 11, 2001 under master turbine contracts qualify for the depreciation bonus if actual work at the project site did not begin before September 11. The Joint Tax Committee staff suggested the turbines should qualify in such cases under a rule that components of a larger project are treated the same as the rest of the project. However, Chuck Ramsey held open the possibility at an industry meeting that, if actual assembly of the turbines started before September 11, that might taint the entire project. (A project that a taxpayer is self constructing qualifies for a bonus only if construction did not begin before September 11.)

In a potentially helpful development, the IRS released a "technical advice memorandum" on September 30 where it denied investment tax credits to a utility that claimed them on a substation the utility built after the investment tax credit was repealed. A "technical advice memorandum" is a ruling by the IRS national office to settle a dispute between a taxpayer and an IRS agent on audit.

The utility argued that it qualified for the tax credit on grounds that the substation was "self constructed." In order to qualify, the utility had to show that construction began on the substation by December 1985. It pointed to the fact that a factory had started assembling transformers for the substation before the deadline, citing an example in a Joint Tax Committee "blue book" involving aircraft where it was enough that work had started at the factory on subassemblies for the aircraft. The IRS said the aircraft example does not apply. Construction does not begin on *facilities built on land* until actual work begins at the site. The ruling is TAM 200239002.

THE DUTCH SUPREME COURT will decide whether a common strategy */ continued page 9*

Giga-NOPR

continued from page 7

two previous orders, both of which were essentially ignored by the utilities that control the grid. This new order is simply one more in a series that began with Order 888 in 1996 to try to address a discriminatory situation. It also establishes a rational market in which to trade wholesale power, but the anti-discriminatory part of it is, in my view, the most important aspect of what the FERC is doing.

MR. MARTIN: Bob Weisenmiller?

MR. WEISENMILLER: On the significance, it is an attempt to take the idea of comparability of service to its ultimate resolution. Along with that, the federal government is trying — with standard market design — to put in place the remaining pieces of the puzzle that one needs to get workable wholesale power markets.

Single Transmission Tariff

MR. MARTIN: Moving to what the government has actually proposed, Julie Simon, what should bankers and CEOs of independent power companies be aware has been put on the table?

MS. SIMON: The single tariff is probably the single biggest thing. I think the push towards a standardized market design is also very, very important. We've seen that, as power markets develop, for a whole host of reasons — ranging from just the way people are used to doing things, to software development and so on — you can have real disconnects between markets that interfere with the free flow of power or so-called seams that prevent power from being moved easily between regions where it can be best used.

As you drill down, there are some other really important concepts in the NOPR itself. The Federal Energy Regulatory Commission's approach to market monitoring is very significant. There will be a very strong role for the market monitors in the regions, as well as the FERC staff, to play with respect to market monitoring.

There is an indication that the government is interested in invasive approaches, similar to those that are currently used in New York and California and with which we are less than comfortable. We think well-designed markets should not require this type of intervention.

Then there is the proposal — which is new from the FERC's perspective — of a resource adequacy requirement—

MR. MARTIN: Julie, let me stop you there and focus on the single transmission tariff. What does "single transmission tariff" mean?

MS. SIMON: You have a situation currently where utilities are required to charge independent generators the same tariffs they use for their own wholesale transactions, but not for their bundled retail transactions. Under the new proposal, there will be something called simply network access service. It is a single approach. Everyone using the grid will be subject to the same tariff and the same requirements for scheduling, information disclosure and so forth. This new network access tariff will be used for all of grid services, including the transmission component of bundled retail service that the utilities currently secure for themselves, sort of offline from the current open access tariff.

MR. MARTIN: I read in one of the flyers for conferences on the giga-NOPR that "the sweeping changes in transmission pricing could dramatically increase sales by low-cost suppliers into distant higher-priced markets." Vito Stagliano, do you think that might be one result from a single transmission tariff?

MR. STAGLIANO: It is the not the single tariff that will ensure that, but rather the requirement for equal access to the grid. It is possible currently for an independent producer to be interconnected to a local grid, but without having the ability to move its power on to the grid or beyond, because of congestion or because the local utility has laid first claim on the scarce capacity on the grid for moving its own electricity.

The giga-NOPR signals a return to long-term contracts for supplying electricity.

The NOPR will address the issue of how equitably everyone will have access to that grid. This is a necessary step in creating a competitive market.

This access issue, and the discrimination that is associated with it, were at the core of two previous orders by FERC in 1996 and 2000. The fact that the federal government has had to issue this new NOPR is evidence that what it did earlier to address the discriminatory access part has not worked to date.

MR. MARTIN: Dave Reich, are there potentially other consequences to this part of the NOPR — the single transmission tariff and equal access?

MR. REICH: Actually, there are. FERC has set up the transmission pricing so that the "load," or person buying the electricity, will pay for transmission service when it ultimately takes power off the grid. FERC wants to vest control over the grid in "independent transmission providers," or "ITPs." In the future, you would be able to move your power from grid section to grid section controlled by different ITPs without having to pay a separate transmission component to each ITP. Thus, load in a distant service territory could contract with a distant independent generator and be able to buy power across several systems, and not have to pay transmission charges except to the ITP where the load is located.

MR. MARTIN: Anyone else, are there potentially other consequences to this part of the NOPR — the single transmission tariff and equal access?

MS. HARGIS: Just one thing: a lot of the opposition to the NOPR has been from regions of the country that feel they have low-cost power and are afraid that that low-cost power will leave and go to other areas where people are willing to pay more. FERC responded that this will not happen because utilities in these regions are free to contract long term for their power and keep it at home. This regional conflict has spilled over into Congress. The governors and regulators from these low-cost regions are trying to get Congress to block implementation of the NOPR.

MR. MARTIN: Which regions of the country are most concerned about their low-cost power going elsewhere?

MS. HARGIS: The South and the Pacific Northwest, and parts of the West.

MR. MARTIN: Another thing in the NOPR — Julie, correct me if I'm wrong — is that utilities will be required to turn over operating control of their grids to / continued page 10

IN OTHER NEWS

that many companies use to avoid capital taxes on money run through holding companies in Holland works.

A lower court said it does not. However, the Dutch advocate general said on July 24 that Holland is barred by the US-Netherlands tax treaty from collecting capital taxes from American companies that use the strategy. Caroline van Riet, a lawyer with Loyens & Loeff in Amsterdam, said the opinion by the advocate general carries considerable weight with the Supreme Court, although the court remains free to decide the case on its own.

The strategy works as follows. A US company forms a Dutch BV as a subsidiary. It capitalizes the BV with a small amount of share capital. A 1% capital tax is paid on that amount. The US company then forms a second subsidiary in Delaware, injects a large sum of money into it, and merges the Delaware subsidiary into the Dutch BV.

Both the tax inspector and the Dutch court of appeals said the strategy does not work to avoid capital tax on the additional capital injected into Holland through the merger. However, the Dutch advocate general said in late July that article 28 of the US-Netherlands tax treaty prevents capital tax from being collected in such cases. The nondiscrimination clause in that article means the parties must be allowed to claim the same "business merger exemption" from capital tax that would apply to European companies engaging in the same transaction.

What will happen if the Supreme Court sides ultimately with the tax inspector: will other US companies that used this strategy in the past now have to pay capital taxes? Possibly yes, reports Caroline van Riet. "The tax inspector could impose tax on Dutch companies involved in similar transactions in the past. The period during which the tax inspector has the authority to do so ends five years after the end of the / continued page 11

Giga-NOPR

continued from page 9

third parties by — is it 2003?

MS. SIMON: Yes. I am not exactly sure of the deadline because it may have been extended.

MR. MARTIN: Is that new, or is that something FERC has been trying to do all along?

MS. SIMON: It has been trying to get to this concept of independent control over transmission for many, many years.

MR. MARTIN: Let me return to a concept we were discussing a moment ago. One expected consequence of the NOPR is there will be no more favoritism for native utility load. Is this because of the single tariff or because an independent party will control the grid or for another reason?

MS. SIMON: It is the result of two things. One is the independent control. The other is the requirement that utilities use the same tariff for their own native load service, because that is where a lot of the discrimination has crept in.

They could do a lot of things to favor their own uses of the grid. It was very hard to get behind whether such uses were legitimate or not. The tariff numbers were not verifiable. The ongoing discrimination that companies like Mirant and Calpine have been wrestling with for years were largely a result of that distinction.

Now there will be a single tariff and the grid will be independently managed. I think we have come a really long way. I think you need both. An independent operator, without a single tariff, will not get you very far.

MS. HARGIS: One other thing worth noting is that the federal government is asserting jurisdiction for the first time over bundled retail transmission — not just unbundled transmission. Bundled retail transmission rates have been left until now to the states. Included in that single transmission tariff that Julie is talking about is the retail tariff.

MR. MARTIN: What is the difference between "bundled" and "unbundled retail transmission?"

MS. HARGIS: "Bundled" is where the prices for the electricity and for moving the electricity are bundled together in a single rate. States historically had jurisdiction over that transmission as part of the retail rates.

"Unbundled" is where each component — for example, the electricity as distinct from the transmission of it and the distribution of it — are priced separately. The state still has jurisdiction over the retail charge for electricity, but the federal government will not assert jurisdiction over the rate for retail transmission.

MR. MARTIN: Why should generators care whether FERC has asserted or extended its jurisdiction?

MR. STAGLIANO: Because it is very difficult for independent generators to determine how much capacity there is on any particular grid as long as there is a lot of bundled retail native load laying first claim to the grid.

12% Reserve Margin

MR. MARTIN: Dave Reich, FERC said in the giga-NOPR that it would like to see a national reserve margin of 12%. What does that mean, and how would it get there?

MR. REICH: This is part of the resource adequacy proposal. I think the federal government is going to leave some discretion to each regions to determine what an adequate reserve margin might be for it. For example, there would be some discretion for the West to have a higher reserve margin because of the amount of hydro resources. Other parts of the country might decide that 12% is okay.

I think what FERC is trying to address with this proposal is to prevent future shortages and price spikes. By putting in place a nationwide reserve margin, there will be more uniform investment in new generating plants across the country, more stable prices, and basically a much better market situation.

MR. MARTIN: What does it mean to have a reserve margin — that there is unused extra capacity to generate?

MR. REICH: The independent transmission provider, or grid operator, will be charged with maintaining the reliability of the grid. As part of that, it will have to make forecasts of electricity demand and supply. You want the ability to call on additional supply that is in reserve for contingency purposes.

MR. MARTIN: Did you say the states will have, in the first instance, to make decisions about how to provide for that reserve?

MR. REICH: FERC is looking at trying to bring the states in as much as possible. They are better situated than the federal government to determine what level of reserves are necessary so that their retail consumers will be adequately served reliably.

MR. MARTIN: Vito Stagliano, where do you think the reserve will come from?

MR. STAGLIANO: We all hope that the utilities will contract with independent generators for this incremental capacity.

The resource adequacy requirement is a challenge to the states by FERC to take responsibility for ensuring there is sufficient supply to meet local needs. This is in sharp contrast to the position that California took a couple of years ago, where it assumed the electricity would come from somewhere and that it had no responsibly to ensure enough local capacity was being built to serve local needs.

MR. O'SULLIVAN: I think that is right on the money. The NOPR was a complete rejection of California's idea that spot markets would provide pricing that would attract investment, in considerable part because the political system will not tolerate freely floating prices. It will not tolerate the kind of high consumer prices you see during periods of capacity shortage. It insists on price caps, but — at the same time — there is no rush to provide price floors during periods of excess capacity to balance out the lost revenues of the independent power producers that result from the price caps.

I think this is a rejection of the idea of short-term markets as the primary market. It signals a return to a long-term contract regime as the basis for most power.

MR. MARTIN: Bob Weisenmiller, you made an interesting comment in June at the Chadbourne conference in Quebec. You asked: "Who is going to build power plants to supply the reserve margin 'just in case'?" Is it reasonable to believe independent generators can be the source of the reserve margin?

MR. WEISENMILLER: To get to the properly functioning market, you must address the question who will pay for the spare capacity. What FERC seems to be saying is let's move to a contract approach, as opposed to, say, a merchant plant approach, where people would build plants on the assumption that — when the markets got tight — the pricing would cover their costs, even if it was a one-in-three or one-in-five-year occurrence.

As John said, we now know that when that one-in-three or one-in-five-year price spike occurs, it will be politically unacceptable. The only way you can really get that additional capacity is with the contract model.

Now, the government must still work out a lot of details in terms of how much reserve is required and who pays for it. In the West, an issue will be who is creditworthy enough to contract? Actually, given the current state / continued page 12

IN OTHER NEWS

calendar year in which the transaction took place."

In a variation on this strategy, some companies inject capital into a subsidiary in another country — for example, the Dutch Antilles or Cayman Islands — and then contribute the shares of the new subsidiary to the Dutch BV. This strategy has also been challenged by the tax inspector. An appeal is expected.

IRS AGENTS are raising questions on audit about a common foreign tax credit strategy involving stapled stock.

The agency released an internal memo in August that discusses how to attack use of such structures.

Most US power companies are unable to claim credit in the United States for taxes paid to another country on earnings from a foreign project. This is because of interest allocation problems. The US views borrowed money as fungible. Therefore, when a US company borrows money purely for domestic uses, the IRS treats part of the interest paid as a cost of the company's foreign operations in the same ratio as the company's assets are deployed at home and abroad. This additional interest expense allocated abroad has the effect of reducing the amount of income that the company is considered to earn overseas. The less income it has from abroad, the smaller the amount of foreign tax credits it is allowed in the United States. The foreign operations of many US power companies are viewed as losing money after this interest expense is taken into account.

US companies try different strategies to get around this problem. One strategy is to "staple" the stock of an offshore company to a US subsidiary. That means that the stock of one company cannot be sold without also selling an equivalent ownership interest in the other company. This / continued page 13

Giga-NOPR

continued from page 11

of the industry, creditworthiness has become an issue on both sides of the equation.

MR. MARTIN: Any other thoughts, anyone, about the 12% reserve margin before we move to the next topic?

MR. STAGLIANO: Yes. It is a major policy decision by FERC in the sense that the federal government has accepted the fact that they are probably going to be unable to create entirely competitive wholesale power markets. So it will rely on long-term contracts in order to meet the requirements of customers.

That is a kind of revelatory position on the part of FERC. One of the issues in California was the fact that the market was dysfunctional within California. Had there been a market that covered the entire Western interconnection, then we probably would not have had the crisis that developed in California in late 2000 and 2001.

FERC is conceding the limitations. It assumes that California still will have only a California market and that the rest of the country will have localized, regional or subregional markets that cannot be made entirely competitive. It could have gone the other way.

MR. O'SULLIVAN: I read it as a broader rejection of the notion that as-available power in spot markets is the same thing as long-term committed capacity. It is a rejection of the economist's model that says short-term pricing will pay the owner of each type of generation an amount to cover the difference between the cost of a peaker and the cost of his plant. FERC has said, whether or not that is true in the abstract, we now know the political system will not tolerate the high prices in times of capacity shortages that are necessary to make investment in generation economically attractive.

In any event, the investors no longer trust the regulators or the markets, so they will not invest, and we will not have enough capacity.

There is a very big question that Lynn Hargis started to raise about whether the FERC has the legal authority to do what it is doing, but I think it is doing exactly the right thing.

MS. HARGIS: The question I have is how does this part of the NOPR fit with curing undue discrimination in transmission? What does FERC point to as its legal authority for this part of the NOPR?

MR. REICH: This is one place where I do not think FERC went far enough. It is merely recommending that load-serving entities contract for the amount of reserves they need; instead of putting in place a mechanism to ensure the reserves, FERC merely put in place penalties for parties who fail to do it.

MR. MARTIN: So this part of the NOPR is a little disappointing?

MR. STAGLIANO: It is less disappointing than it is not very well thought out. FERC believes that local load serving entities will assume the responsibility for contracting for all the electricity they need, plus a reserve margin.

It may be, in the end, that those load-serving entities will find it simpler merely to pay the penalty in the spot market when they run short than to commit themselves to long-term contracts with people who will provide reserve capacity.

MR. MARTIN: I read somewhere that utilities will be penalized if they are short on power and have to take from the spot market during a shortage. You just referred to this. What is the penalty in such cases?

MR. STAGLIANO: The penalty would be the equivalent of whatever the spot market price would be at that time. However, since the spot market price is subject to price controls imposed by FERC, in terms of both a regional bid cap, plus an automatic mitigation procedure, the utility already knows how much exposure it is likely to have, and it may prefer to accept that price rather than negotiate a long-term deal.

MR. MARTIN: So there is no separate penalty; it is just the utility will have to pay spot prices during periods of shortage?

MR. STAGLIANO: That's right.

MR. O'SULLIVAN: There is also a suggestion that when there have to be curtailments, the systems that are short will be the ones curtailed first.

Price Caps

MR. MARTIN: Next topic: Julie Simon, the NOPR proposes circuit breakers or price caps designed to limit the prices that generators can charge. How does this work?

MS. SIMON: It creates what is called a "safety net bid cap" of $1,000. The idea is that if prices are running up quickly, some amount of demand would, under normally competitive circumstances, get off the system. But we don't have in place yet all the right mechanisms to send those price signals and let load do that.

There is also the concept of "must-offer obligations" that would be negotiated in participating generator agreements in particular locations in order to address more limited kind of load pocket problems.

MR. MARTIN: So this part of the notice — the bid caps and must-offer obligations — are they aimed at dealing with California-type problems, or are they aimed at a broader problem?

MS. SIMON: I think both California and broader. They are aimed at preventing future Californias. We will have mechanisms in place before the fact with which people can work so that we don't get into the kind of crisis mentality we had in California.

However, I think the thing that they are really doing with respect to California is approving an "AMP," or "automated mitigation procedure." There is a requirement that if an independent transmission provider wants to use additional mitigation — that is, beyond the $1,000 bid cap and the limitations in the participating generator agreements — then it must come back with some kind of a showing that such steps are warranted. This is an important recognition that the type of heavy-handed approach that was used in California can be counterproductive for encouraging new investment. A lot of power plants that were planned for California are being put on hold right now.

MR. MARTIN: Because of the price caps, or for other reasons?

MS. SIMON: It is a combination of reasons. But frankly, the current price cap in California is $91.68, or something like that. That is not the right price signal for power plants that are on call for periods of peak demand. It is hard to build a peaking plant at that level of return.

MR. MARTIN: Other thoughts from people on the call about this part of the notice, the part designed to deal with market distortions or disruptions? Why is this significant for generators? What should a banker or CEO of a generator take from it?

MR. STAGLIANO: Its significance for generators is that FERC thinks it must impose price controls in order to respond to the politics of marketing power. Markets do not operate efficiently with price caps, no matter what the level of those price caps is. Rather than focusing on creating a broader, deeper, more liquid market that goes beyond the limitations of a single region or a single state, FERC fell back to the loud demands of the state utilities commis- / continued page 14

IN OTHER NEWS

turns the offshore holding company into a US taxpayer, but it is not part of the consolidated group headed by the US parent company. As a consequence, it is not weighed down by the allocated interest expense of the rest of the consolidated group. This puts it in a position to use foreign tax credits.

The IRS memo is from the national office to an IRS agent in the field about possible ways to attack use of this strategy in a pending audit. The memo is FSA 200233016.

ELECTRIC INTERTIES continue to absorb IRS time.

Independent generators connecting their power plants to the grid must usually reimburse the local utility that owns the grid for the cost of the equipment required to interconnect. The IRS repeated last December that utilities ordinarily do not have to report such interconnection payments from generators as income. The notice applies to interconnection arrangements completed after December 26, 2001. However, the IRS said it would issue private rulings, when asked, confirming that the same rules apply to past payments.

The agency had received seven such ruling requests through late September. (Chadbourne drafted five of them.) One of the seven rulings has been issued. Another was expected as the *NewsWire* was going to press. Rulings in this area take approximately five months.

The one ruling already issued is interesting. The IRS told an electric cooperative that it did not have to report as income the value of a transmission line that was paid for by a private generator. The coop owns the line. The generator wanted to put its power on the grid in two places. One of the two delivery points was in another state and required construction of a long transmission line. A nearby coop could use / continued page 15

Giga-NOPR

continued from page 13

sioners who would like to see wholesale prices limited to some extent by retail rates. I think that is what the NOPR does.

MR. WEISENMILLER: Another point to take from this discussion is it will be very important what the precise details are and how this part of the NOPR is implemented. It has not been particularly well thought out. You could see a lot of investment put on hold until the industry learns the details.

MR. O'SULLIVAN: That investment is on hold now anyway, isn't it?

MR. WEISENMILLER: Yes, but it may remain on hold while people are working through how this part of the NOPR will be implemented.

Tradable Transmission Rights

MR. MARTIN: Dave Reich, we have talked so far about the single transmission tariff, the requirement that utilities turn over operation of their grids to independent third parties, the 12% national reserve margin, and the bid caps and must-run obligations. Is there anything else in the giga-NOPR that is important for generators to know?

MR. REICH: Underneath the single tariff, there are the congestion revenue rights that FERC proposes to create and that would be tradable.

MR. MARTIN: What are those?

MR. REICH: Basically, you would have a defined path from point A to point B on the grid. What the commission will put in place is locational marginal pricing, so that every point will have a price associated with it and if there is congestion, there will be different prices between the two points. That price difference times the amount of power flowing between the two points is congestion revenue. A customer who holds a congestion revenue right between point A and point B could avoid paying the congestion revenue between those two points.

MR. MARTIN: What are the tradable rights?

MR. REICH: FERC has proposed that each point-to-point customer and network customers would have congestion revenue rights based upon their historic usage of the grid. Paths such as the A to B example would be assigned to each transmission customer based upon his historic transmission usage. A customer could trade or sell the right associated with those paths to receive or avoid congestion revenue to another company that values those rights more than the original holder of the congestion revenue right.

Over the course of a 4-year transition period, the commission will probably move to an auction approach, where you would go from basically physical transmission to financial transmission. That's also a pretty big step under the NOPR.

MR. MARTIN: Have we covered all the main points about the giga-NOPR or is there anything else people want to mention?

MR. STAGLIANO: I believe that we have covered the main points.

Subtle Consequences

MR. MARTIN: Does the call by FERC for a return to a long-term contract regime offer some hope to generating companies that — without waiting for everything else to be sorted out — we can start getting back to financeable contracts?

MR. STAGLIANO: My sense is that comfort in the industry will not come until all of these cases before the FERC, brought by people challenging previous contracts that were entered in good faith, have been resolved satisfactorily. I will withhold judgment as to what is acceptable in the marketplace until all of these challenges have been settled and we see where we come out.

MR. MARTIN: Dave Reich, do you agree?

MR. REICH: Completely. It's hard to take comfort in the notion that we will voluntarily enter into a long-term contract, and that the terms of the contract will remain in place over the life of the deal, when customers are still filing complaints, and the commission is still setting them for hearing, and we are stuck having to litigate the terms and conditions of contracts that were mutually agreed to when the contracts were signed.

Until those cases play out, there is really not a very high comfort level going forward.

MS. SIMON: I think what the commission has done is to reopen the question of who should be building new power plants.

MR. MARTIN: How so?

MS. SIMON: Seventy-five percent of the investment in generation that has been made in the last three years has been made by the competitive industry. I think the question that the NOPR is asking — not directly, but it is raised indirectly by the resource adequacy portion of the NOPR — is, are we going to go back to integrated resource planning and have utilities build generation again? Our side of the industry has proven that we can build stuff faster, less expensively, cleaner and so forth. But I think some people may take this as an indication that the utilities are meant to get back into the building business. It is not at all clear that we will continue to build 75% of all of the new capacity in this country.

MR. MARTIN: So FERC has thrown that decision about who builds back to the states?

MS. SIMON: I think indirectly FERC has thrown it back to the states. FERC has not totally left it up to the states. But for example, one of the things that we have been talking to people about is a requirement that the resource adequacy be competitively bid. There is no requirement in the NOPR for that type of an approach.

Now, FERC may have just taken that for granted. However, it is something that I think we must raise in the comments. I think FERC has been intentionally vague in the rulemaking because it did not want to dictate to the states how they could be involved in this process. FERC has opened the door to a partnership here. It really wants to work with the states, and the NOPR is not particularly prescriptive about how this will be done.

MR. O'SULLIVAN: It also raises a question for regulatory lawyers as to who would have the authority — depending upon how this adequacy initiative is structured — to approve the prudence of utility purchases. Is it the states or the federal government?

Generally, since most of the electricity was ultimately going to retail customers, the states have done most of that. But I think it is possible, just as the FERC is declaring its jurisdiction over the transmission component of retail sales, that it could also make pre-emptive judgments about the prudence of a purchase — if it has the authority at all under the Federal Power Act to go ahead with the resource scheme.

MS. SIMON: There's an additional problem that I think we'll hear in the comments from some of the utilities that are under rate freezes.

MR. O'SULLIVAN: You are exactly right.

MS. SIMON: Some of the utilities that are currently under rate freezes are very concerned about whether or not they will be able to ensure a flow-through of costs in state retail rates. That will be for the lawyers to sort out. */ continued page 16*

IN OTHER NEWS

eminent domain to get the land rights to build the line. It had no use for the line for its own purposes. The generator plans to retain title to the electricity passing over the line, but to pay the coop nothing for wheeling the electricity over the line. Intertie payments to a utility do not have to be reported as income by the utility, but only if the generator is not a customer of the utility for wheeling or other services. In this case, the IRS concluded there was no customer relationship. Electric coops are exempted from US income taxes, but must be careful that any income comes from the right sources to retain their tax exemptions.

In another development, Wildflower Energy, LP, an independent generator that connects to the Southern California Edison Company grid, asked the Federal Energy Regulatory Commission to order Edison not to collect a "tax grossup" in addition to charging it for the costs of interconnection. Edison maintains that the tax treatment of interconnection payments from Wildflower is unclear. FERC said it could not settle a tax dispute and directed Wildflower to ask the IRS for a ruling. However, it ordered Edison to refund the tax grossups *with interest* in the event a favorable ruling is received. Edison has not been offering generators to pay interest.

SIX SYNFUEL PROJECTS are under audit by the IRS.

At issue is whether the projects qualify for section 29 tax credits. The US government offers a tax credit of $1.083 an mmBtu for making "synthetic fuel from coal." All of the projects mix chemical reagents with crushed coal. All have private letter rulings from the IRS national office confirming that the processes in use at the facilities qualify for tax credits. These rulings were issued on the basis of studies that the owners of the projects submitted with */ continued page 17*

Giga-NOPR

continued from page 15

MR. O'SULLIVAN: Assuming FERC has the authority to begin with to do the resource adequacy part of the NOPR, if FERC approves the prudence of the purchases, then that is probably pre-emptive; that is, the states would be under an obligation under the supremacy clause of the US constitution to allow the utilities to recover their payments.

MR. STAGLIANO: My belief is that instinctively, state regulators will feel much more at ease if the new capacity that is built is somehow integrated into the rate base, thereby avoiding questions about whether or not a particular contract is prudent.

It is for this reason that they feel much more comfortable with rate-based new investment. We now have anomalous situations in places like Louisiana, where the local monopoly utility is actually talking about building a new nuclear power plant.

The last time I looked at the economics of nuclear power plants, they worked only when the investment was written off as stranded investment, not when it was newly made.

So, we are going to encounter, I think, difficult situations in most states, where there will be this tension between what the state public utility commission would rather do, and what would otherwise make economic sense to do.

Timetable

MR. MARTIN: Julie Simon, what's the timetable for this NOPR, comments and then what?

MS. SIMON: FERC issued an extension of the comment deadline last week, and so comments are now due November 15th, with reply comments due December 20th. I think that makes it unrealistic that we will see a final rule in the first quarter of 2003. I expect them to get a final rule out in the late spring. Others may have other ideas. Then the implementation is obviously going to take place over a number of years. There are different phases of implementation. For example, the congestion revenue rights that David Reich mentioned are initially allocated and then transitioned to an auction over several years.

MR. O'SULLIVAN: You have to allow in your schedule for litigation.

MS. SIMON: Normally, FERC's approach is not to incorporate that into their process. It assumes that you don't unscramble these eggs. It has a pretty good track record of winning the big ones. So FERC generally puts these things into place, everybody gets used to them, and litigation goes on a parallel track.

To date, no court has been willing to stay any of these FERC rulemakings, but obviously, that would be a huge delay if a court were to actually stay implementation of the rule pending some type of judicial review.

MR. O'SULLIVAN: If we were looking for renewed investment in generation or transmission, that is not going to happen until the litigation risk is gone, right?

MS. SIMON: I think it's hard to know. I think the power prices right now are sending a signal that there is adequate investment for the short term. If you look at the NERC reliability studies, at least through 2005-2006, we are seeing very high reserve margins.

Obviously, we have a lot of regulatory uncertainty and a lot of overhang in the industry for a whole host of reasons.

But a change in any one of those reasons could turn the industry around. If the economy were really to pick up, for example, and power prices were to begin to reflect the reduction of a capacity margin, people might respond to price signals very quickly. They do not need to be $6,000 price signals in order to make new investments. But obviously, the more stable a regulatory climate, the better for additional investments.

MR. STAGLIANO: The trouble with the FERC schedules is that they almost are never real. We were on one schedule with Order 2000, which has essentially been abandoned by the new schedule for this NOPR, which may drag out for the next four to five years.

What that really means, aside from the uncertainty for new investment, is tied to the issue of what you do with the investment that is already in the ground. The discriminatory regime that the FERC is trying to address with the new NOPR, will remain in place until the final rule takes effect, which means that we have, at least in my view, four more years of slogging through the present unhealthy situation before we get to a probable, although not a definitive, end with a competitive market.

MR. MARTIN: Does anyone believe that the uncertainty surrounding the rules during this period that the NOPR is being discussed will make it harder to finance new projects?

MS. SIMON: I don't think it makes it easier. But as Vito said, and as I said earlier, I think project financing turns on a lot of criteria, and regulatory certainty is obviously one of those. The more certainty the better for investment in general, but that is not the only factor at which people look. Overall, this NOPR is definitely a positive for the industry.

MR. MARTIN: Dave Reich, you are in Washington. Is there any danger that Congress will block parts of this?

MR. REICH: We have certainly been monitoring that. There are members of Congress who would like to delay its implementation.

MR. MARTIN: Western and southern regulators are the most unhappy with this. Is this because of the potential export of low-cost power that Lynn Hargis mentioned earlier?

MS. SIMON: I think it comes from, in many cases, a concern that their vertically-integrated utilities are not going to retain the competitive advantages that they have currently, which is obviously — as we've been talking about for the last hour — the goal of this rulemaking.

I think in some states, there is also a real hesitancy to trust a federal approach right now.

Final Thoughts

MR. MARTIN: Let me try to sum up and ask for reactions. It seems that one part of this proposed rule is a single transmission tariff and equal access to the grid. That part is seen universally by generators as a plus. Does anyone disagree?

MR. REICH: It is a huge plus. It is also one of the things that can be implemented very quickly by FERC.

MR. STAGLIANO: I tend to be a skeptic about the ability of the FERC to police what it issues as orders. This discriminatory issue has been around ever since we've all been around. FERC has simply not been able to resolve it. So the fact that the FERC issues an order, or several orders, is no guarantee that it will impose discipline to comply with that order on the part of the people who should.

MS. SIMON: I understand where Vito's coming from, but I think this is historic in the sense that the FERC for the first time is asserting jurisdiction over the transmission part of bundled retail service.

Regardless of whether or not FERC accepts the independent power industry comments on the notice, the statement in this rulemaking that the federal government intends to go down this path — it is huge and should not be underestimated. It is a sea change in terms of the federal government's willingness to attack the problem of discrimination.

MR. MARTIN: The next part of the */ continued page 18*

IN OTHER NEWS

their ruling requests from outside chemistry labs showing that the output from the plants differs significantly in chemical composition from the raw coal used to produce it. Nevertheless, IRS agents in the field are taking a hard look at this type of facility.

One of the audits is expected to close without any adjustment. The oldest of the remaining audits started 15 months ago. The IRS field staff is trying to coordinate its approach to the audits and is reportedly planning to hire an outside expert, possibly from one of the chemistry labs that the syncoal plants have been using, to advise it on the audits.

Meanwhile, the IRS tightened its ruling policy further in early August. The agency said last year that it will continue to rule that the use of chemical reagents to make synfuel qualifies for tax credits as long as the chemical reagent falls into one of four categories the IRS had approved for use by the end of 1999. However, Joseph Makurath, the IRS official who signs rulings, said in early August that the agency will only approve for use in the future the *specific* reagents that it had approved earlier. It will not approve any new reagent, even though it fits in one of the four broad categories. Makurath said the IRS views the tax credits as encouraging innovation only during a window period that has already closed.

Taxpayers with ruling requests pending are being asked by the IRS to prove that the reagents they propose to use were covered by earlier rulings.

THE US EXPORT-IMPORT BANK held a public hearing on September 24 to discuss its new proposed procedures for determining whether an Ex-Im Bank financing might have an adverse economic impact in the United States.

Changes in how the */ continued page 19*

Giga-NOPR

continued from page 17

giga-NOPR is a mixed bag from the generator's view — the national reserve margin of 12%, the notion embedded in the proposed rule that there ought to be more long-term contracting for the power. For generators, it is a move in the right direction, but the details have not been filled in and, when the details are filled in, they could lead — at the end of the day — to more construction of new power plants by the regulated industry, not by the competitive industry.

Is that a fair summary?

MR. STAGLIANO: If the resource adequacy requirement is market-driven — in other words, if it is managed through some sort of open bidding process — then the possibility of addressing it correctly is high. On the other hand, if it relies entirely on bilateral arrangements, in the absence of a competitive bidding process, I believe that it will have problems being implemented.

MR. MARTIN: Dave Reich, do you agree?

MR. REICH: No, not on the bilateral part. As long as the states have some sort of competitive bidding process, like Julie Simon was talking about, where we can compete and the decisions are based upon who is the lowest-cost supplier, and then you enter into a bilateral contract to provide the electricity, then those kind of details will work for us.

MR. MARTIN: The last segment of the giga-NOPR is the circuit breakers, price caps, things like that. Is it fair to say that generators are not especially pleased with this part of the giga-NOPR, because of the potential for distortion in price signals and the potentially deleterious effect on new investment?

MS. SIMON: We have real problems with the way the mitigation is currently designed in the rule. The commission recognizes some important concepts about the need for generators to recover their investments. There is some positive language in the giga-NOPR for the first time.

The proposed mechanisms are problematic. However, the commission has recognized some important things about the interplay between price mitigation and the need for people to recover their costs in some type of a capacity payment. FERC had not shown it understood this before. The commission has not taken the right steps to fix that problem, but it has at least recognized the problem. That is important.

MR. O'SULLIVAN: There is language in the NOPR indicating that the commission is not convinced that, even without constant price caps or the constant threat of price mitigation, there will be sufficient investment in generation on a timely basis to avoid the sort of vicious circle of capacity shortages and high prices and the re-imposition of price caps. FERC said the fact that the political system has been so ready to oppose price caps effectively moots the debate; investors will not invest where they're shaved on the high side and not supported on the low side.

MR. STAGLIANO: A key issue with the price mitigation part of the NOPR is, how much discretion will be allowed to the states to apply the mitigation measures? If FERC allows flexibility in implementation to permit regional variations, then you can be sure that the regions will take full advantage of the variations that they want. California is already unhappy with the $92 price cap that is currently in place. I don't know how it will be happy with the $1,000 one. The issue is how all of this laudable intent will be carried out in practice in different regions of the country.

MR. REICH: This is where the devil is in the details. Depending upon how the commission decides to price those mitigation measures, they could have a chilling effect on the market.

MR. MARTIN: Bob Weisenmiller, you get the last word.

MR. WEISENMILLER: I think you started out with the question of is this really important. I think we have hit the ways that the giga-NOPR could reshape the industry. FERC has articulated a vision. It wants to move away from the merchant plant model to more of a long-term contract model, and it has articulated an intention to involve the states in that process.

We are moving in the right direction. There is an awful lot of work to be done, and there are a lot of details still to be filled in. ◎

Tax Issues In Debt Restructurings

by Heléna Klumpp, in Washington

Many banks and US power companies are currently engaged in debt restructuring talks, but the parties to these talks are not always aware of the minefield through which they walk. There is the potential in a debt restructuring inadvertently to trigger taxable income for the borrower, the lenders, or both.

The debt restructuring negotiations this year may be little more than a warmup for next year and the year after, when estimates are that as much as $30 billion in short-term loans — called "mini-perms" — will come due that banks made to finance merchant plants.

This article explains where the tripwires are located. It focuses on exchanges of new debt for old as a way to present the basic issues, but it also discusses the ramifications of having lenders convert loans into stock in the borrower and potential traps for which both parties should be on the lookout.

"Significant Modification"

Many debt restructurings involve something as simple as an extension in the repayment schedule. The interest rate could change. Other terms could be relaxed to enable the borrower to repay rather than force the borrower into default. The borrower might have to post additional security. Affiliates of the borrower could be required to guarantee repayment.

There can be tax consequences for both parties.

An outright exchange of an existing debt for a new one could trigger gain or loss. There is also a concept known as a "deemed" exchange; the parties do not have to write a new loan, but they might be considered to have done so if the terms of the existing loan change enough that the loan is considered to have undergone a "significant modification." The lender will then have to determine whether it has taxable gain or loss by comparing the value of the new loan to its "tax basis" — generally the outstanding loan principal — in the old loan. For example, the lender would have a loss if the market value of the restructured debt is less than the principal amount the lender was owed earlier. Meanwhile, the borrower must determine whether part of its debt has been effectively cancelled, in which case the borrower may have to report "cancellation of indebtedness," or "COD," income. Section 108 of the US tax code may excuse the borrower from having to report the income if the renegotiation of loan terms occurred while the borrower was insolvent or going through a chapter 11 bankruptcy proceeding. However, none of these issues arises unless the changes in loan terms rise to the level of a "significant modification."

Whether a modification or group of modifications is significant enough to be treated as an exchange must be tested against guidelines found in Internal Revenue Service regulations. Under the guidelines, a / continued page 20

IN OTHER NEWS

bank lends are required by the "Export-Import Bank Reauthorization Act of 2002" that became law in June. The act reauthorized the bank's operations for an additional four years. It also both codified and broadened existing restrictions that prevent the bank from supporting transactions deemed detrimental to the US economy.

The economic impact procedures were first ordered by Congress in 1968 to help the bank more efficiently weigh the competing priorities of supporting US exports but not doing so in a manner that threatens long-run adverse economic consequences in the United States.

The new law would effectively block Ex-Im Bank financing in two specific situations in the future. The first is where a financing would support production of a product that is the subject of either a countervailing duty or antidumping order under title VII of the "Tariff Act of 1930." Under this restriction, the Ex-Im Bank may not finance foreign projects whose products have been found to have been sold at unfairly low prices with an adverse effect on the US market. An example is steel. The second is where, following a global investigation into an industry, called a "section 201 investigation," the US International Trade Commission has determined that the US economy has been injured by excess supply in the market.

The Ex-Im Bank is now reviewing its economic impact procedures to comply with these new requirements. Likely innovations include requiring notice and comment periods for all financings exceeding $10 million to an entity that either is subject to a preliminary anti-dumping or countervailing duty determination or that produces products for which a section 201 investigation has been initiated. Other possible revisions involve requiring the bank to consider section 201 investigations as indicative of an oversupply condition when / continued page 21

Debt Restructuring

continued from page 19

restructured debt is significantly different than the original debt if the yield on the loan increases by 25 basis points or 5% of the annual yield on the original loan, whichever is greater.

Any "material deferral of scheduled payments" is a significant change. The IRS does not treat a delay as significant as long as the payment is "unconditionally payable" within five years or 50% of the original loan term, whichever is less. The delay is measured from the "original due date of the first scheduled payment." For example, if the lender of a 20-year loan agrees in year 11 to let interest for the next four years accrue and be paid in a lump sum in year 15, that is not a modification since it is within the limit allowed.

The parties to an existing loan can trigger taxes if they "significantly modify" the terms.

With a few exceptions, changing the borrower on a *recourse* debt instrument is automatically significant. One exception is where the borrower is acquired by another company in certain kinds of tax-free reorganizations. Even then, the change will be considered significant if there is a "change in payment expectations" on the loan.

Changing the borrower on a *non*recourse loan is never considered significant.

A change in the collateral or other security for a *recourse* loan is only significant if it causes a change in "payment expectations." A change in security for a *non*recourse loan is significant if it replaces a "substantial amount" of the collateral. An exception is where the collateral is fungible. A change from recourse to nonrecourse or vice versa is always significant.

Debtor Concerns

Debtors — especially those whose debt is publicly trading below face value — need to approach a potential restructuring by first considering whether it will create taxable COD income.

Unfortunately, this inquiry is more complicated than simply comparing the principal amount of the old debt to that of the new. The amount of COD income is measured by comparing the "issue prices" of the old and new debt. The issue price of a debt instrument is a number that most accurately reflects the instrument's true value. In determining the consequences of an exchange, the idea is to compare the true values of both instruments to each other, and the issue price of a debt instrument provides a better reflection its value than its "face" or principal amount does. To make a borrower's analysis even more difficult, different rules apply to determine the issue prices of the old and new instruments.

Starting with the old debt, its issue price in many cases should equal its face amount. However, if the debt was issued at a discount, then its issue price is equal to the price at which the debt was issued, increased by the amount of the discount that has accrued to date on the debt. For example, a company may borrow $700 but promise to repay the lender $1,000 in 10 years when the loan matures. The debt has $300 of "original issue discount, "or "OID." The issue price of that debt is $700. The $300 discount accrues over the life of the loan. The issue price is adjusted over time to include such accruals. Thus, on any given date, the "issue price" of the old debt is $700 plus the discount that has accrued up to that date.

The issue price of the old debt must be compared to the issue price of the restructured debt to determine whether the borrower has COD income. It does if the issue price of the restructured debt is less.

The issue price of the restructured debt depends on whether either it or the old debt is traded publicly on an established securities market. If either debt is publicly traded, then the issue price of the restructured debt will be its fair market value. This is because that value should be easy to determine by checking the market listings on the date the debt restructuring is concluded. However, if neither debt instrument is publicly traded, then the issue price of the restructured debt is its "face," or principal, amount. (The face amount is used only if the interest rate charged on the restructured debt is at least equal to the applicable federal rate.)

In practice, COD income is not a problem in debt restructurings where neither of the debt instruments is publicly traded, unless the lender agrees to write off some of the loan principal.

Parties to publicly-traded debt should be very careful about restructuring a debt instrument when it is trading below face value. If the debt is significantly modified in the restructuring, then the borrower will have COD income equal to the amount by which the value of the instrument has dropped below the price at which it was originally issued (adjusted upwards for any accruals of OID). For example, if a borrower restructures a debt with a $1,000 face amount that has dropped in value to $700 and the face amount of debt remains at $1,000 after the restructuring, then the debtor will have $300 of COD income. The amount of COD income is the difference between the face amount of the original debt, which is $1,000 (assuming it wasn't issued at a discount), and the value of the new bond, $700 (set by reference to the market value of the original debt for which it is being issued).

Possible Relief

The borrower can avoid some or all of the COD income in such situations if it can show it is insolvent or by waiting to restructure the debt until it has filed for chapter 11 bankruptcy.

An "insolvent" debtor for this purpose is a debtor whose liabilities exceed the fair market value of its assets. An insolvent debtor does not have to report COD income, up to the amount of its insolvency. However, there is a tax cost: the debtor is required to reduce certain "tax attributes" for every dollar of COD income that escapes taxation. Tax attributes are particular types of tax benefits that the debtor may have, such as net operating losses, tax credits, and capital losses carried forward from prior years. The debtor must reduce any of these items it has in a certain order until the forgiven COD income has been fully absorbed. A debtor may elect to apply the reduction first against its tax basis in any depreciable property it owns. Although this may seem like an obvious choice to make, a lower tax basis will */ continued page 22*

IN OTHER NEWS

making economic impact determinations. Another currently debated revision would require a 14-day notice and comment period before the Ex-Im Bank board could act on financings supporting products that are subject to a final antidumping or countervailing duty order or a section 201 injury determination. The deadline for comments on the proposals is October 10.

The Ex-Im Bank is an independent US government agency that helps finance the sale of US exports — primarily to emerging markets — by providing loans, guarantees, and insurance.

ARGENTINA said in September that it will no longer require Argentine borrowers to get prior approval from the central bank before making principal and interest payments on certain loans from foreign lenders.

The new policy applies to existing debts that have been restructured as follows. The lender must have agreed to write down the principal amount of the debt by at least 40% of its nominal value on the restructuring date. The interest rate cannot exceed the 6-month LIBOR rate plus 3%. Interest payments cannot be required more frequently than quarterly. The average life of the debt must be at least four years from the restructuring date. The lender must allow a grace period on principal repayments of at least two years.

Getting approval to repay other foreign debts will be more difficult, in view of the shortage of foreign reserves in Argentina, according to Diego Serrano Redonnet of the law firm Perez Alati, Grondona, Benites, Arntsen & Martinez de Hoz in Buenos Aires. "It is yet to be seen whether this new regulation will enhance the ability of companies to negotiate favorable restructuring deals with foreign creditors," Serrano Redonnet said. */ continued page 23*

Debt Restructuring

continued from page 21

mean lower depreciation deductions going forward, as well as greater taxable gain if the assets are sold.

Related Parties

A borrower might unwittingly also trigger COD income by having an affiliate buy back its debt at a discount in the market.

If a company acquires debt of a related party from an unrelated party, the debtor will be forced to recognize COD income, if any. Such an acquisition could occur in one of two ways. The first way is a direct acquisition of the instrument itself — in other words, the related party buys the debt instrument from the unrelated holder. The second way is an indirect acquisition. This is a transaction in which an unrelated party acquires the debt instrument and then becomes related to the debtor through a corporate acquisition. "Related" generally means that there is more than 50% overlapping ownership between two parties.

Lender Concerns

Lenders need to be careful that a restructuring does not create taxable gain. This could occur if the restructuring increases the value of the debt. The analysis is the same as for the borrower. A mismatch between issue prices of the old debt and restructured debt is unlikely in practice unless at least one of the debt instruments is publicly traded. A debt restructuring might be structured in form as a tax-free "recapitalization" of the borrower. A lender facing a potential loss might prefer a taxable transaction so that it can claim the loss.

Even if a lender gives up more than it gets in return and thus has an economic loss, it may have to report taxable income from the restructuring. If a debt is restructured between interest dates or in any other situation where accrued interest has not yet been included by the lender in income, a portion of the consideration paid to the lender as part of the restructuring will be treated as the interest on the original debt that has accrued but has not yet been paid. Any such amount is taxable as ordinary income. It will increase the lender's "tax basis" in the original debt for purposes of determining its overall gain or loss on the restructuring. (Since the loss may be a capital loss, the lender could be whipsawed because that capital loss cannot be used to offset the ordinary income.) A lender may have an argument that no portion of the consideration should be allocable to interest if the debtor is in a questionable financial position and the collectibility of the interest is doubtful. This is an especially important point to keep in mind in cases where the restructuring is prompted by the debtor's current inability to make payments on the old debt.

Bottom Fishers

Another issue should remain on the radar screen for any holder of a debt instrument who was not the original lender. An example is a "bottom fisher" who buys corporate or project debt in the market hoping to make a profit when the borrower recovers. A bottom fisher is more likely to show a gain after a debt restructuring. If the restructuring leads to a "significant modification" of the original loan, it will trigger a tax on any gain, and — worse still — the tax rules may recharacterize what would otherwise have been capital gain as ordinary income. This means that a corporate holder can only use ordinary losses — as opposed to capital losses — to offset that portion of the taxable gain.

This result stems from the fact that the bargain price paid by the holder when it acquired the debt reflects an economic benefit known as "market discount." Simply put, assuming the debt is ultimately paid in full, the holder will get back more income than it paid for. A holder of a debt instrument with market discount can either wait to report the market discount as income when the underlying debt instrument is paid off or resold, or the holder can elect to report the market discount as it accrues. Any holder of a debt with unaccrued, unreported market discount will have to recharacterize any gain it has on the restructuring as ordinary income.

Even if a holder has no gain from a restructuring, any market discount on the old debt could affect the holder going forward. This is because the market discount on the old debt will be converted into OID on the new debt if either instrument is publicly traded. This occurs due to the way one computes the issue price of a bond that is publicly traded. The resulting OID will have to be taken into income by the holder over the remaining term of the debt; the holder cannot wait to report it all at once at maturity as it could with market discount. This conversion will occur if two things are true of a debt with market discount: first, either the new or old debt is traded on an established securities exchange and, second, the market value of the old debt has dropped below its face amount.

Conversion into Equity

One option for a struggling debtor with little cash today but decent growth prospects is to offer its creditors stock in exchange for their debt instruments. Some debtors might prefer this route because it can improve a company's balance sheet at the same time as it reduces interest expense, without any up-front cash outlay. The tax consequences are similar to those of a debt-for-debt exchange (or debt modification): the debtor might have COD income and the lender might have a gain or loss.

The key question is how to value the stock received in the exchange for purposes of calculating the debtor's COD income and the lender's gain or loss. The debtor is treated as having satisfied the debt with an amount of money equal to the fair market value of the stock. Therefore, if the stock is worth less than the principal amount of the debt, then the debtor will have COD income.

The lender does the same calculation to figure out whether it has a gain or loss on the exchange. It compares the market value of the shares it received to its tax basis in the debt instrument. If it acquired the debt at a discount from the face amount, it could have a gain. The lender will have to report part of the stock value as ordinary income to the extent there was accrued, unpaid interest on the debt instrument that the lender has not yet included in income at the time of the exchange.

Tax-Free Recapitalizations

The parties to a debt restructuring might try to structure it as a tax-free "recapitalization." This only works if the borrower is a corporation. It will not spare the debtor from having to report any COD income, and it may only limit the amount of gain the lender must recognize as taxable income.

A recapitalization can take many forms, but it is generally described as a reshuffling of a corporation's capital structure. Examples include an exchange of new debt instruments for old ones, or the issuance of corporate stock in exchange for the cancellation of an old debt instrument. As long as a transaction is motivated by business — as opposed to tax avoidance — concerns, many structures

/ continued page 24

IN OTHER NEWS

BRAZIL increased the PIS tax rate from 0.65% to 1.65% effective on December 1, but also allowed a crediting mechanism that will reduce the taxes owed in some cases.

The PIS tax is a monthly tax on gross income of Brazilian companies. The receipts are used to fund a federal social integration program. The government announced the rate increase in provisional measure 66/02 on August 29. However, it said, at the same time, that companies will be allowed in the future a credit for PIS taxes already paid earlier in the production chain. Credit will be allowed for taxes already paid on certain goods acquired for resale and on depreciation of machinery and equipment used in manufacturing.

The government plans to create a similar, noncumulative system for the 3% COFINS tax by December next year, according to José Roberto Pisani and Yoon Chung Kim with Pinheiro Neto Advogados in São Paulo. The COFINS tax is a social security levy. It works the same way as the PIS tax in that it is collected on monthly gross income.

Brazil has also created a special PIS and COFINS tax regime for electric generating companies that opt to use it. The special regime allows receipts from certain power sales to be excluded from the tax base.

PERU threatened to renegotiate tax stability contracts with foreign investors, but then backed away.

A tax stability contract is a promise by the government not to change the tax rules that apply to an investment. Such contracts are often signed to induce foreigners to make long-term investments in the local economy.

The finance minister made the threat in early August after the government lost arbitrations with two electric generating companies over whether each can claim full tax depreciation on

/ continued page 25

Debt Restructuring

continued from page 23

are acceptable. One exception is that a stockholder cannot convert its shares into debt and call it a recapitalization. (It will be viewed as an outright sale of the shares.) Another requirement is that the instruments being exchanged must either be corporate stock or "securities." Although the definition is not precise, securities are generally understood to be obligations of a corporation to pay a certain sum of money. Generally a debt must have a term of at least five years to be considered a security, but other terms of the instrument are important as well.

A debtor reaps no benefit from structuring an exchange as a tax-free recapitalization; it can only benefit the lenders. Lenders who would otherwise have to report a gain from the restructuring might find such a structure appealing.

A lender has taxable gain in a tax-free recapitalization only to the extent it receives "boot" in the transaction. "Boot" is consideration other than common stock, some forms of preferred stock, and securities. An example of boot is cash. ◎

Anticipating A Possible Bankruptcy

by N. Theodore Zink and Francisco Vazquez, in New York

Creditors renegotiating debt terms should keep a watchful eye on the potential bankruptcy implications of the proposed restructuring, lest the troubled borrower eventually wind up in bankruptcy.

In exchange for certain concessions designed to alleviate the borrower's financial distress, lenders to troubled borrowers often try to enhance the prospects for full, albeit delayed, repayment by adding co-obligors through affiliate or other third-party guaranties, taking more collateral, and seeking to limit management flexibility in a way that may maximize lender recovery at the expense of other creditors.

However, aspects of the new deal could be unwound by a court if the borrower subsequently files for bankruptcy. Upon filing for bankruptcy, a debtor enjoys certain protections, including an automatic stay under section 362(a) of the US bankruptcy code that enjoins most creditor enforcement activities. Further, under the bankruptcy code, debtors are granted broad powers to reject executory contracts and unexpired leases and to claw back or negate certain transfers made on account of pre-existing obligations or for less than reasonably equivalent value within a certain time period before bankruptcy. In addition, the bankruptcy code grants courts the power to subordinate the claims of a creditor to the claims of other creditors notwithstanding the contractual or statutory priority of such claims.

Accordingly, when negotiating an out-of-court restructuring, lenders should anticipate what may occur if the restructuring fails and the debtor files for bankruptcy.

This article discusses what savvy lenders should know when negotiating for credit enhancements and other lender protections in an out-of-court restructuring.

Promise Not to File

Lenders in debt restructurings often require the borrower to promise that it will not subsequently file for bankruptcy protection. The bankruptcy courts have uniformly refused to enforce covenants not to file, on the basis of furthering public policy in favor of unfettered access to bankruptcy relief.

Unwind Risk

The bankruptcy laws are designed to promote fairness and facilitate equality of distribution among similarly situated creditors. They establish a priority scheme that sets the order for making distributions to the different types of creditors. They also provide that certain transfers during the runup to bankruptcy may be unwound or "avoided" because they demonstrate a preference toward the recipient creditor at the expense of other creditors.

"Preferential" Transfers

Lenders should be aware that a transfer that is made by an insolvent company within 90 days of its bankruptcy filing may be set aside by the bankruptcy court. The 90-day period is extended to one year if the creditor is considered an "insider" in relation to the debtor. This could happen if the creditor received more before filing than it otherwise would if it stood in line with the other creditors in a typical bankruptcy proceeding.

A "transfer" includes every mode of disposing of property or an interest in property, including the granting of a security interest. The bankruptcy code does not limit the avoidance of preferential transfers to any specific type of creditor or transfer.

The intention of the parties in making the transfer is irrelevant.

Creditors need to think carefully about whether the restructuring creates payments or deemed payments that could be unwound by a bankruptcy court in the future. Sometimes, as part of a workout, a creditor will require a debtor to make a meaningful payment on the outstanding debt in exchange for a relaxation of terms for the remaining obligation. This payment could be clawed back if the debtor then declares bankruptcy within 90 days. In addition, the grant of new or additional security for an existing loan may be later avoided because, at the end of the day, the additional security will allow the lender to receive more than it otherwise would have in the bankruptcy case.

However, not all preferential transfers are susceptible to being unwound. A creditor has defenses to prevent a preference from avoidance in cases where the creditor is not just restructuring, but extending new or additional credit.

Another important planning point is the substitution of collateral of equal value is generally not avoidable as a preference. Moreover, the granting of an additional lien is not a preference where the lender provides additional loans after the security interest is granted. Lenders must be careful that the restructuring documentation is drafted so as not inadvertently to restart the 90-day or one-year preference period as it relates to preexisting collateral security.

Fraudulent Conveyances

In addition to preferential transfers, the bankruptcy laws permit the avoidance of "fraudulent conveyances."

In general, a transfer, or an obligation incurred, may be avoided as a fraudulent conveyance in two situations. One is where the debtor made the transfer or incurred the obligation with an actual intention to hinder, delay or defraud creditors. In other words, one must prove actual fraud on some of the debtor's other creditors. The other is where the debtor received less than reasonably equivalent value for the transfer or new obligation.

In addition, it must also be shown either that the debtor was insolvent at the time of the transfer or the incurrence of the obligation (or becomes insolvent as a result of the transfer or obligation), it retained an unreasonably small amount of capital for the business in which it was / *continued page 26*

IN OTHER NEWS

assets acquired in a merger with another company that already depreciated them. The arbitrator said the double depreciation benefit was available by law when the government privatized the companies, and tax stability contracts signed with the foreign owners bar the government from changing the rules. A third electricity generator owned by Duke Energy paid an undisclosed amount in December to settle its dispute.

However in September, the finance minister declared that the contracts are "sacred" and will not be amended unilaterally by the government, reports Rafael Rossello, a tax lawyer with the firm Hernandez Rossello in Lima.

The head of the tax agency, Sunat, had said contracts with 570 companies were under review. Peru reopened such contracts with foreign oil companies once before in the 1970's. The government is facing a budget shortfall after it had to cancel plans this summer to privatize state electricity assets in southeastern Peru in the face of violent public protests.

CALIFORNIA said that out-of-state generators who sell electricity into California earn their income outside the state.

At issue is whether franchise taxes must be paid on the income. The ruling — by the State Board of Equalization in a case involving PacifiCorp — helps generators and power marketers who sell electricity into California.

PacifiCorp protested franchise taxes that California said it owed for the period 1984 through 1989. The company sold excess power during those years into California from power plants in Oregon, Washington, Wyoming and Utah. Corporations are subject to franchise taxes in California on income from California sources. A company's California income is determined by taking all of its income and then / *continued page 27*

Anticipating Bankruptcy

continued from page 25

engaged, or the debtor intended to incur, or believed it would incur, debts that would be beyond its ability to repay.

Fraudulent transfers made within one year of the bankruptcy may be recovered under federal law. Earlier fraudulent transfers may be recovered under state law depending on the relevant state law reach-back periods.

Lenders should be aware that loan guarantees may be affected by the fraudulent conveyance rules. It is common in out-of-court restructurings for lenders to require a third-party guarantee in exchange for concessions made by the lender. Most often, such guarantees are provided by an affiliate of the borrower. Inter-company guarantees, and other third-party guarantees for that matter, raise fraudulent conveyance concerns because the guarantor may not receive an exchange of reasonably equivalent value in exchange for the guarantee. Reasonably equivalent value does not require that there be an exchange of exactly the same value; it requires substantially equal value.

The guarantees that are least likely to be unwound are those for which the lender can show the guarantor received a tangible benefit. In general, downstream guarantees — that is, from a parent for a subsidiary's debt — are not avoidable as a fraudulent conveyance because the parent typically benefits from the guarantee in the form of the credit extended to the subsidiary. However, both upstream — that is, from a subsidiary for the parent's debt — and cross-stream — from a subsidiary for a sister subsidiary's debt — guarantees are susceptible to avoidance as fraudulent conveyances because the benefit is not always as clear; reasonably equivalent value is not always given to the subsidiary guarantor. Moreover, guarantees extended in the restructuring context may be subject to avoidance on the basis that no new loans were extended and, accordingly, the guarantor did not receive reasonably equivalent value in exchange for the guarantee.

Lenders should also recognize that credit enhancements provided by the borrower's affiliates in the form of guarantees and collateral security may blur the separateness of the individual firms within the consolidated enterprise in a way that may promote an argument for substantive consolidation in a subsequent bankruptcy of the borrower or its affiliates. In other words, the more that affiliates of the borrower are involved in pre-bankruptcy restructurings, the more likely those affiliates — and their assets — are to be pulled into a subsequent bankruptcy proceeding of the borrower. Bankruptcy courts have the power to ignore the separation between corporate entities that are under common control by pooling the assets of affiliated entities and requiring all creditors to look to the common pool of assets for payment on their claims. The power to consolidate may significantly affect the rights of debtors and creditors and is therefore used sparingly. Therefore, lenders may wish to be particularly skeptical of the ultimate value extended by third parties in workout situations. While lenders should continue to require credit enhancement through inter-company guarantees and collateral grants, they should do so fully aware of their potential vulnerability in a subsequent bankruptcy case.

Equitable Subordination

A final area of caution: A creditor's claim may be subordinated in bankruptcy to the claims of other creditors under the common law doctrine of equitable subordination. The doctrine has been codified in section 510(c) of the US bankruptcy code. It authorizes a court to subordinate a creditor's claim to the claims of other creditors in response to certain misconduct that results in harm to the other creditors.

While the bankruptcy code authorizes the equitable subordination of claims, it is silent about when equitable subordination is appropriate. Courts have almost uniformly held that three conditions must be satisfied. First, the creditor must have engaged in some inequitable conduct. Inequitable conduct may in fact be lawful, but regardless of its legality shocks "good conscience." An example is secret and unjust enrichment caused by unconscionable double dealing.

Second, the misconduct must have resulted in injury to other creditors or confer an unfair advantage to the creditor whose claim is to be equitably subordinated. This factor is satisfied — for example — if the misconduct led to an increase in the misbehaving creditor's claim or a reduction to the distributions received by other creditors.

Finally, equitable subordination of the claim must be consistent with the principle in the bankruptcy code that there should be equal distribution among similarly-situated creditors. Given its underlying purpose, equitable subordination is remedial in nature and is not intended to punish creditors and, therefore, claims are generally subordinated only to the extent necessary to address a clear harm to innocent creditors.

Collection activity, and by extension efforts to enhance the ultimate collectibility of a loan through restructuring, may under certain circumstances subject a lender to a challenge under equitable subordination. Where a creditor exercises undue control over the debtor's decisionmaking process, a creditor may be accountable for his actions under a fiduciary standard. However, this should only be a problem in very unusual circumstances. Lenders should not feel constrained to act meekly when negotiating a restructuring.

Conclusion

While we do not advocate that lenders forego the credit enhancements traditionally sought in the context of out-of-court restructurings or tread lightly when dealing with a delinquent borrower, it is important that lenders, when negotiating restructuring agreements, remain mindful of the various bankruptcy risks that may arise if the restructuring does not achieve its intended consequence. Some types of rights for which a lender might negotiate in a debt restructuring are less likely to be set aside in a subsequent bankruptcy than other rights. It is useful to keep in mind the distinction. ◎

Mexican Electricity Reforms?

by Alejandro Silva and Mario Juarez, in Washington

President Vicente Fox sent the Mexican Congress an energy reform package in mid-August. The initial reaction in Congress was sour, but the package is starting to attract support. It is still too early to say whether it will be enacted.

The president called on Congress to amend the Mexican constitution, to make substantial revisions in the laws governing the electricity sector, and to adopt new laws under which the regulatory agencies — the Comisión Reguladora de Energía, or "CRE," and the Centro Nacional de Control de Energía, or "CENACE" — and the two government-owned power companies — the Comisión Federal de Electricidad, or "CFE," and Luz y Fuerza del Centro (the distribution company in the Mexico City metropolitan area), or "LFC" —would operate in the future. */ continued page 28*

IN OTHER NEWS

allocating a portion to California based on a three-factor formula that looks at the percentage of its total workforce, property and sales that is in California. Sales of "tangible personal property" are considered to occur where the customer is located. However, sales of services occur where the physical work is done to create the service. The State Board of Equalization said electricity is a service. Therefore, the sales in this case occurred outside California where the electricity was generated. The board released its formal opinion in the case in late September.

There is no consistency among states on how they view electricity. The inconsistency opens the door to tax planning since it is theoretically possible to allocate sales to no state by selling into states like California from states that allocate the sales to the place where the customer is located. The issue also comes up frequently in "tolling" transactions: states are often confused about how to apply sales taxes, which are collected on retail sales of "tangible personal property," but may or may not be collected on sales of services. In a "tolling" transaction, a gas supplier pays the owner of the power plant fees to convert its gas into electricity.

TAX PLANNING MEMOS from an accounting firm had to be turned over to the Internal Revenue Service, but similar written advice from two law firms was protected from disclosure.

The IRS sought seven documents in connection with its tax audit of a large telephone company. A federal district court judge in Wisconsin said recently that two opinions from the law firm Jenner & Block about transactions to generate tax losses were protected from disclosure by the attorney-client privilege. However, she ordered the company to turn over to the IRS a letter from Arthur Andersen to */ continued page 29*

Mexico

continued from page 27

Constitutional Amendments

The main purpose of the proposed amendments to articles 27 and 28 of the Mexican constitution is expressly and unequivocally to authorize private parties to generate electricity either for self-supply purposes or to sell power to CFE, LFC or large consumers. Large consumers are defined in the reform package as those consuming more than 2,500 megawatt hours a year.

Mexico is debating what role private electricity suppliers should play.

Private generators cannot sell power to the CFE or large consumers unless article 28 is amended to make only the supply of electricity for public services a national strategic area reserved to the public sector. Such an amendment would leave open the definition of electricity public services so that Congress could define through secondary laws the extent of electricity public service.

Thus, while the CFE and LFC will continue to enjoy a monopoly on the retail market, the energy reform package, if approved, would promote private projects that could supply power to the government-owned distributors as well as compete against the CFE in supplying power to large consumers, arguably the CFE's most lucrative market. It would also provide much needed legal certainty for the current private generator model, a welcome change after the recent Supreme Court ruling. (For a discussion about the Supreme Court ruling, see "Mexican Ghoulash" in the August 2002 *NewsWire*.) .

Electricity Public Services Law

The reform package would amend the "Electricity Public Services Law" to limit the electricity public services concept to the supply of electricity to residential and retail customers. Such supply would be off limits to private companies. Everything else would be fair game. The upshot is that private companies would have legal authority to be involved in the generation and sale of electricity to large consumers and the CFE. The current available mechanisms for private sector involvement — cogeneration, self-supply, independent power production and export — would remain available.

Another important proposed change in the Electricity Public Services Law is the institutional strengthening of the CRE. It would be given authority to fix, adjust and restructure electricity tariffs. It would also have the required regulatory powers to enforce open access to the CFE's transmission and distribution networks by the new private generators.

Other Amendments

These amendments, if passed by Congress, would create a dual power sector in Mexico under which private and public companies would compete to supply power to large consumers. In order for such system to work, the public distributors would have to provide open access to their transmission and distribution networks. Otherwise, the private generators would be unable to get their electricity to market.

A strong regulatory and dispatch framework needs to be created and implemented in order for generators to be able to sell spot capacity efficiently on the wholesale market, either to the public distributors or to large consumers. The energy reform package would enhance the regulatory role of CRE over all sector participants and put in place an economic dispatch system. CENACE would be put in charge of implementing and controlling dispatch of both public and private generators.

As part of the government's proposals, the CFE and LFC would be restructured to try to impose more efficient and transparent — in other words, less politically motivated — operations and resource allocation. To that end, CFE will be granted new powers to act more independently of the central government. The CFE's operating statute will be amended in its entirety so that the CFE can be run in a way similar to a private company. Theoretically, this should improve the level of service and allow the CFE to compete with private power producers for the coveted large consumer market. CRE will continue as the regulatory agency in charge of granting permits for power generation and surveying the activities carried out by energy industry participants. CENACE would be separated from the CFE. New authorities will be granted to CENACE to provide an efficient control dispatch of public and private generators and guarantee to all energy users access to the national grid and the national electric system under the same terms and conditions.

Political Challenges

Since the swearing in of the Fox administration, the opposition parties have expressed their rejection of any reform that would allow a major increase in the private sector involvement in the energy industry. In particular, the opposition parties have been adamantly opposed to amending the Mexican constitution. Indeed, after the Supreme Court decision earlier this year that cast a cloud over the legality of existing private power projects, it appeared that the position of the opposition PRI party and other parties against the Fox energy policy would strengthen. (The court blocked the government's attempt to allow greater private sector involvement without having to run any reforms through Congress.)

However, with the passage of time, some industry analysts and lawyers in Mexico now think that the court's decision has given a boost to Fox's view that a constitutional amendment is required to provide a solid legal basis for existing private power projects as well as for any future involvement of the private sector in power supply. Indeed, the Supreme Court itself urged Congress to consider a constitutional reform.

It was under these hazy conditions that the Fox administration unveiled its energy reform package. Immediately after the plan was released, both major opposition parties rejected the government's proposal and said they remain opposed to any legal scheme to allow private investment in the energy industry.

However, that was their initial response. Things appear to be changing. There are signs of disagreement within the PRI and PRD — the two main opposition */ continued page 30*

IN OTHER NEWS

the company that "outlines the federal income tax consequences of the transactions at issue." She acknowledged that it was similar to the Jenner & Block opinions, but said the attorney-client privilege did not apply because "this is accounting advice from an accounting firm and not legal advice from a law firm." She suggested the way to protect the Arthur Andersen opinion would have been to have had the advice run to the law firm in connection with the legal opinion the firm was writing.

She also ordered the company to turn over an outline that Arthur Andersen prepared as a "framework for addressing legal issues" in the transactions. At the same time, she allowed the company to withhold a Sidley & Austin memorandum and attached markup of the Arthur Andersen tax opinion on grounds that it was privileged.

The case is a reminder to tax departments about the need to be careful about what is put in writing and by whom. It is US v. Telephone and Data Systems, Inc.

AN OIL PIPELINE is not subject to real property taxes, a Maryland appeals court said.

The pipeline runs across Maryland on its way from Texas to New Jersey and is buried about 36 inches below ground. The pipeline company does not own much land in the state, but rather has easements from landowners over whose property the pipeline passes. The Maryland tax department tried to collect real property taxes, but a state court of appeals said no such taxes have to be paid in this case because the pipeline is considered "personal property" rather than real property. It is closer to movable equipment than a building. The court rendered its decision on September 9.

The case is Colonial Pipeline Company v. State Department of Assessments and Taxation. */ continued page 31*

Mexico

continued from page 29

parties — about what position to take, and some party members have even expressed support for the Fox proposal. The head of the PRI, Roberto Madrazo, said recently that there would not be a party-line approach to the energy reform package, freeing PRI congressmen to vote as they please. Support by members of the opposition is critical since any amendment to the Mexican constitution must be approved by two thirds of the members of Congress, as well as by a majority of the 32 state legislatures. The government party, PAN, has no majority at the federal or state level.

In late September as the NewsWire was going to press, the energy reform package faced an uncertain outlook in Congress. The legislative and constitutional approval process is difficult and full of political minefields. The Fox administration has sent Congress other major initiatives, only to see them rejected or, as was the case with the recent tax reform, approved in a manner completely different than what the government intended. However, there is some hope in this case that a reasonable compromise may be reached, allowing all parties to claim the political high ground in next year's congressional elections.

Other Challenges

Many in the industry in Mexico believe that the energy reform package, if approved, must be coupled with other major reforms in the supply of the gas to private power plants. Pemex has mentioned several times that new infrastructure investments are needed to keep up with demand for gas. Pemex does not have the necessary budget to build this infrastructure and traditionally has preferred to invest its resources in oil production, which usually gives it a much higher rate of return. The Fox administration and Pemex now hope that a new contractual structure — called "multiple services contracts," or "MSCs" — will increase the involvement of private companies in the exploration and exploitation of natural gas. Pemex estimates that with this contractual structure, the production of gas will increase to meet, or at least help to meet, the supply of gas for power plants. Pemex is expected to award the MSCs through international bids in the near future.

Finally, some developers have told Chadbourne that they are concerned that the CFE's transmission and distribution infrastructure will have to be materially revamped before any new projects can be assured of delivering their power to large consumers. Private generators will almost certainly have to contribute to these system upgrades needed to the grid. This could be a significant cost for future projects. ◎

International Commercial Arbitration

by William Perry and Reka Koerner, in Washington

This article discusses why arbitration — as opposed to other means – is usually the preferred method for settling disputes in cross-border transactions. It also suggests some basic rules of thumb when drafting arbitration clauses in contracts to avoid common pitfalls.

Arbitration is widely regarded as a preferred method of resolving international commercial disputes. Among other advantages, it provides security against being forced into another party's local courts where there may be a "home field" advantage. Arbitration can be confidential, is generally more flexible than litigation, and is frequently less expensive and less time-consuming as well. Moreover, in many countries a foreign arbitration award — that is, an arbitration decision rendered in another country — is easier to enforce than a foreign court judgment.

However, in order to receive the advantages of arbitration, the arbitration clause in the contract must be properly drafted. A "standard" arbitration clause or one that does not adequately take into account international arbitration law and treaties can be a serious problem and can lead to a situation where the arbitration never moves forward or the award is unenforceable. While drafting an arbitration clause is usually one of the last things on a business person's mind when negotiating a transaction, it warrants attention; it may well prove to be the most important provision in the contract if the business relationship sours.

Importance of Treaties

Arbitration awards are easier to enforce than court judgments in foreign countries due to several international treaties. However, there is no single arbitration treaty that applies to all countries. Therefore, it is important to match up the parties to a contract, and their major assets, to an international arbitration treaty that provides for the enforcement of arbitral awards. An arbitration clause is of little use if the prevailing party in arbitration is unable to enforce the award against the assets of the losing party.

The most important international arbitration treaty is the "New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards" — a 1958 treaty that is referred to simply as the "New York Convention." It has been ratified by more than 120 countries and territories, and an arbitration award issued in one of those countries can generally be enforced in any other country that has ratified this convention.

The New York Convention recognizes certain limited defenses to enforcement of an arbitral award. These include the following. First, an award cannot be enforced if the arbitration clause was void under the law selected by the parties in the contract or the law of the country where the award was rendered. Second, it cannot be enforced if the parties were not given proper notice of the arbitration. Third, another defense to enforcement is the arbitration tribunal ruling on matters beyond the scope of the arbitration clause. Fourth, enforcement of the award can be blocked if it would violate the public policy of the enforcing country. If the New York Convention is properly implemented, these defenses will typically be construed and applied very narrowly (although the "public policy" defense has occasionally been a problem in some countries).

If a deal involves a Latin American party, consideration should be given to whether the relevant country has ratified the "Inter-American Convention on International Commercial Arbitration," a 1975 treaty called the "Panama Convention." There is substantial overlap between countries that have ratified the Panama and New York conventions and the two treaties have similar provisions. However, some countries, like Brazil, have ratified the Panama Convention but not the New York Convention.

There are various other international arbitration treaties or conventions that may apply to a given transaction, some with a regional or subject-matter specialization. If a governmental entity and an "investment dispute" are involved, then the "International Center for Settlement of Investment Disputes between States and Nationals / continued page 32

IN OTHER NEWS

TAX TREATIES do not override statutes enacted later by Congress, a US appeals court said.

Air Liquide, a French company, paid royalties to its US subsidiary. The US subsidiary wanted to put the royalties into the "general limitation basket" for purposes of calculating foreign tax credits.

American companies are allowed to claim credit for any taxes they already paid to another country on their incomes. In theory, this is supposed to prevent the same income from being taxed twice — once abroad and again in the United States. However, foreign tax credits are almost impossible for US companies in capital-intensive industries to use in practice because of fine print in the US rules. One way the US inhibits use of credits is by requiring that income be divided into different "baskets" depending on the type of income. Credits put into one basket cannot be used to shield income in a different basket from US tax.

Air Liquide argued that an anti-discrimination clause in the US-France tax treaty requires the US to treat the royalties as "active" business income. The Internal Revenue Service insisted the royalties belong in the "passive" basket. The 9th circuit court of appeals noted that the US Congress enacted the basket regime in 1986. The treaty was signed in the 1960's. The court said that later legislation — and IRS regulations issued under later legislation — override treaties.

The case is American Air Liquide, Inc. v. Commissioner.

MINOR MEMOS. The Interstate Natural Gas Association of America is expected to ask the US Treasury Department for a ruling that gas intertie payments do not have to be reported by interstate pipelines or gas utilities as taxable income. It wants / continued page 33

Arbitrations

continued from page 31

of Other States" — called the "ICSID" or "Washington Convention" — may apply. Additionally, the World International Property Organization in Geneva, Switzerland established an arbitration center in 1994 for intellectual property disputes. Bilateral treaties on the recognition of arbitral awards also exist between many individual countries.

What Rules to Choose

An arbitration clause should indicate whether the arbitration will proceed under the supervision of an international arbitration institution or without the supervision of an institution but under pre-existing arbitration rules. The experts call this a choice between an "institutional" arbitration and an *"ad hoc"* arbitration. Depending on the type of arbitration selected, the parties will need to give thought to which institution they wish to select — in the case of an institutional arbitration — or the rules they want to govern — in the case of an *ad hoc* arbitration.

Among the most prominent of the international arbitration organizations are the International Chamber of Commerce, or "ICC," the London Court of International Arbitration, or "LCIA," and the American Arbitration Association, or "AAA." Each of these institutions has its own rules for conducting the arbitration. Each also supervises such matters as the appointment of and challenges to arbitrators. Each can help overcome procedural obstacles, particularly in the early stages of the arbitration, before the tribunal is fully constituted.

In an *ad hoc* arbitration, the parties and arbitration tribunal manage the arbitration themselves, but typically incorporate by reference an agreed set of procedural rules, such as the rules drafted by the United Nations Commission on International Trade Law, known as the "UNCITRAL rules." The UNCITRAL rules are specifically designed for *ad hoc* international arbitrations. If procedural disputes arise before the tribunal is fully constituted and able to act on its own, the UNCITRAL rules provide for an "appointing authority" to decide such disputes as disagreements on the selection and disqualification of arbitrators. The parties should identify an appointing authority in the arbitration clause to avoid problems in reaching such agreement after a dispute arises. Many institutions that typically administer their own arbitrations – such as the ICC or the LCIA – are willing to be named as the appointing authority for an UNCITRAL arbitration. If the parties cannot agree on an appointing authority, then the UNCITRAL rules provide for the Permanent Court of Arbitration at The Hague to designate the appointing authority.

There are advantages and disadvantages to both institutional and *ad hoc* arbitration. Institutional arbitration tends to be more expensive because of the administrative fees involved, but it is often preferred because of the stabilizing, neutral role institutional oversight can play in a proceeding. An established institution can provide the parties with a clear set of rules, a history as to how the rules are implemented, and a readily accessible forum for resolving procedural disputes. Institutional arbitration is a particularly good choice where one of the parties has not had any prior experience with international arbitrations or is from a country that has not been arbitration-friendly. On the other hand, the single most important factor in a successful arbitration is not whether it is "institutional" or "ad hoc"; it is the quality, experience and competence of the arbitrators. For this reason, an *ad hoc* UNCITRAL arbitration can be just as effective in the hands of a good arbitration tribunal and a competent appointing authority. A proactive *ad hoc* tribunal can handle many of the procedural matters that are addressed by institutional rules and provide the parties with more autonomy.

When choosing an international arbitration institution to administer the arbitration or to act as the appointing authority in an *ad hoc* UNCITRAL arbitration, there are several factors to take into account, including the institution's reputation, access to qualified arbitrators, stability, and cost. First, the institution's reputation and whether it is perceived as neutral may be important to the ability to enforce the award. If the institution is well respected internationally and is perceived as geographically neutral (not "pro-Western"), then there will be less opportunity for the losing party to claim that the arbitration process was biased or manipulated. Second, the more specific the contract is about the backgrounds of the arbitrator to be chosen, the more important it is that the selected institution be able to draw from a broad pool of potential arbitrators. Third, institutional stability and longevity are vital since the arbitration clause may fail if the institution no longer exists when a dispute arises.

Each of the three international arbitration institutions noted above — the ICC, LCIA, and AAA —has an international reputation, and at the end of the day it will not matter greatly which one is selected. Their rules are more alike than different, and the outcome of an arbitration is not likely to differ simply because one institution is chosen over another. In the past, parties in certain regions — such as Asia — have been reluctant to use the ICC, viewing it as a Western institution that solves problems on Western terms, although the ICC has been working to overcome this perception. The AAA in the United States has suffered from the same perception problems.

Of these three institutions, the ICC probably will provide the most administrative oversight, but it also charges the most for administrative services. The LCIA charges less for less oversight. On balance, however, the relative difference in administrative fees among these institutions – which can be driven by such things as the amount in controversy, the complexity of the dispute, and the amount of oversight actually required – tends to be overshadowed by the fees and expenses of the arbitrators themselves, which will be much more significant and can easily exceed a combined total of $100,000 (in some cases, much more) in a multimillion dollar case of moderate complexity.

Good Arbitration Clauses

Structuring an effective arbitration clause is more complicated in the international than the domestic realm. Matters such as designating the place of arbitration may seem simple, but are full of traps for the unwary.

There are at least five issues that a well-drafted international arbitration clause should address. They are the scope of the arbitration, the place of arbitration, the number of arbitrators and any essential qualifications, the language of the arbitration, and the applicable substantive law. While there are many other considerations that can make arbitration more efficient and may affect the outcome, they are beyond the scope of this article.

First, the arbitration clause should define the scope of the matters that the parties intend to refer to arbitration. Unless the parties have a good reason for carving out a specific issue that they do not wish to resolve through arbitration, the arbitration clause should be broad. Broad clauses typically define the scope of the arbitration as "any controversy or claim arising out of or */ continued page 34*

IN OTHER NEWS

a ruling similar to a ruling the US government issued last December on electric intertie payments. Treasury officials report receiving no contact yet from the trade association . . . . A power company in Pennsylvania is appealing a federal district court decision that culm is not "biomass" for tax purposes. "Culm" is the dirt, rock and other debris that is deposited above ground outside underground coal mines. If the material were "biomass," then a power plant that burns it would qualify for faster tax depreciation. A federal district court said earlier this year that it is not . . . . The Joint Tax Committee staff is spending its free time studying tax returns filed by Enron. The staff hopes to make a report to the tax-writing committees in Congress by year end on what Enron did to reduce its US income taxes. Senate hearings are possible next year.

—contributed by Keith Martin, Heléna Klumpp, Samuel R. Kwon, Kristin Meikle, Luis Torres, Kenneth W. Hansen, W. Robertson Milbourne, Jr. and Megan Prout in Washington, Caroline van Riet in Amsterdam, José Roberto Pisani and Yoon Chung Kim in São Paulo, Diego Serrano Redonnet in Buenos Aires, and Rafael Rossello in Lima.

Arbitrations

continued from page 33

related to" the contract or "all disputes, controversies or claims arising in connection with this contract." If the arbitration clause lists specific issues that are subject to arbitration instead of using broad, general wording, the other party may claim that anything not specifically listed is not subject to arbitration.

Second, the parties should give careful thought to the place of arbitration and designate the city and country in the arbitration clause that will be considered to be the "seat" or "situs" of the arbitration. This is an important legal concept: although the hearings may be held elsewhere, the "seat" of the arbitration is where the award is deemed to have been issued. In selecting the "seat" of arbitration, the parties must consider whether the host country has ratified one of the international treaties regarding arbitration awards. If it has not, then the arbitration award may not be enforceable in other countries. An additional consideration in selecting a "seat" of arbitration is whether the country's laws and legal culture favor or tend to obstruct the arbitral process, since recourse may be necessary to the host country's courts to resolve issues that arise during the course of the arbitration proceedings. Even if a country's laws favor arbitration, caution is warranted before arbitrating in a country where one of the parties is connected to the government (or is the government itself), although as a practical matter this may be difficult to avoid in negotiating some transactions.

Third, the arbitration clause should specify the number of arbitrators that will sit on the parties' tribunal and any essential arbitrator qualifications.

An arbitration tribunal typically will consist of either a single arbitrator or three arbitrators. There are several issues that should be taken into account in deciding whether to opt for a single- or a three-member tribunal.

A single-member tribunal is less likely to result in delays once the arbitration is underway since it will not be necessary to coordinate three tribunal members' conflicting schedules. However, delays may occur before the tribunal is constituted if the arbitration clause or rules require the parties to agree on the single arbitrator or there are arbitrator qualifications specified in the arbitration clause. The parties will inevitably disagree on the other side's proposed arbitrator and whether an individual meets the qualifications of the arbitration clause. There is more at stake if there is just one arbitrator.

Three-member tribunals are favored in major disputes because many parties are not comfortable entrusting a significant decision to a single arbitrator. A three-member tribunal allows for the selection of arbitrators of different nationalities and with different areas of expertise. It is difficult to find a single arbitrator who will bring as much experience to the process as a well-selected three-member tribunal. However, in addition to the disadvantage of having to coordinate the schedules of three arbitrators, a three-member tribunal may be more prone to allegations of bias. If the parties decide they want a three arbitrator tribunal, then the applicable rules will typically provide that each party will nominate one arbitrator and the third arbitrator — the chairperson — can be appointed by the two party-nominated arbitrators, the institution, or the "appointing authority." Although all of the tribunal members are required to be neutral (and most arbitrators are), in some cases there can be a lingering perception that a party-nominated arbitrator is biased in favor of the appointing party.

Regardless of whether the parties decide that a single- or three-member tribunal best suits their needs, they should specify the number of arbitrators in the arbitration clause. Failure to do so will lead to a default decision. The default rules of the ICC, LCIA and AAA provide for a single arbitrator unless the institution decides that three are warranted. The UNCITRAL rules provide for a default three-member tribunal.

In addition to the number of arbitrators, the parties can also require in the contract that the arbitrators have certain qualifications, such as fluency in a language or expertise in a particular area. However, only truly essential qualifications, if any, should be included, because they will limit the pool of available qualified arbitrators. Significant problems may arise if there are no available arbitrators that meet the arbitration clause criteria.

Fourth, the arbitration clause should specify the language for conducting the arbitration. If the parties do not select a language in advance, then the arbitrators will make the selection after the tribunal is constituted. Until then, uncertainty about which language will govern may make it difficult to nominate an appropriate arbitrator and, in the case of a three-arbitrator tribunal, for the party nominated arbitrators to select a chairperson. While the chairperson of a three-arbitrator tribunal is usually not supposed to be a national of any country involved in the arbitration, he or she should be familiar with the language of the arbitration. Finally, once the tribunal is constituted, it could potentially select a language that causes significant inconvenience to one of the parties.

Fifth, the arbitration clause should designate the substantive law that will govern the parties' dispute. If the parties do not agree to a choice-of-law provision, they may face uncertainty as to how to perform under the contract in ambiguous situations, and the arbitrators will be left to determine the governing law after the fact. The choice-of-law provision should clearly state that it applies only to the substantive law governing the dispute. If the parties do not distinguish between substantive and procedural law, then the choice of law provision may be read to conflict with the procedural portions of the arbitration clause.

Most institutions, as well as UNCITRAL, have suggested "model" arbitration clauses. These suggested arbitration clauses should be used as a starting point. The parties can then add additional provisions or specifications that fit their needs.

Avoid "Pathology"

Frederic Eisemann, while secretary general of the ICC in 1974, described arbitration clauses that were unenforceable as written or were certain to lead to disagreement over their interpretation as "pathological." To avoid the pathology of a poorly drafted arbitration clause from infecting the well-being of your business transaction, keep it simple and clear, think ahead, consult the basic guidelines described in this article and obtain advice on international arbitration law. ◎

Brownfield Projects

by Roy Belden, in New York

Companies redeveloping old industrial sites or so-called "brownfields" in the United States may be eligible for significant federal and state tax benefits on environmental remediation costs. The federal brownfields tax incentive is intended to encourage development of contaminated industrial sites. In addition, many states have enacted programs to provide tax credits or other tax benefits for developers of contaminated sites. A combination of the federal brownfields tax incentive and state tax breaks and other inducements may help reduce project development costs and improve the financials of the project.

Federal Tax Incentive

The federal brownfields tax incentive allows taxpayers to deduct immediately the cost of certain environmental remediation and redevelopment activities. It applies regardless of whether the company redeveloping the property caused the contamination or is working on a site that was contaminated by someone else. Without this provision, taxpayers would be required to capitalize most of these types of costs, which means that the costs would be added into the tax basis of the property. The taxpayer could still recover the capitalized costs, but it would do so much more slowly through depreciation deductions for the property or in the manner of a smaller taxable gain when the property is sold.

In order to qualify for the federal brownfields tax incentive, a taxpayer must incur "qualified environmental remediation expenditures" at a "qualified contaminated site."

Three things must be true of a site for it to be considered a "*qualified contaminated site*." The property must be held by the taxpayer in its trade or business or for the production of income. Property that is held as inventory for anticipated sale to customers also qualifies. This means the taxpayer cannot be developing the site for its personal use. It also means that the taxpayer must either own the site or be in possession under a long-term lease. Second, a state agency must certify either that a release of a hazardous substance has occurred or that the threat of a release exists. The list of hazardous substances is comprehensive, but some notable exceptions include petroleum, asbestos and lead paint in buildings, and naturally-occurring contaminants like radon. Finally, the property cannot be listed on — or be under consideration for — the "National Priorities List" of contaminated sites compiled by the Environmental Protection Agency pursuant to the so-called "Superfund" legislation. */ continued page 36*

Brownfield Projects

continued from page 35

A *"qualified environmental remediation expenditure"* is a cost incurred to control or remove a hazardous substance from a qualifying site. Costs related to site assessment and investigation generally qualify, as long as such activities are part of an overall effort to control a hazardous substance. Generally, spending on depreciable property such as the equipment used in the cleanup effort does not qualify, though there is some leeway if the equipment is dedicated to the particular site.

Additional restrictions apply to otherwise qualifying cleanup costs that were incurred prior to December 21, 2000. When originally enacted in 1997, the brownfields deduction was slated to expire at the end of 2000 and was limited to development activities in certain economically-distressed areas of the United States. Congress eventually amended the statute, extending the expiration date to December 31, 2003 and lifting all geographic restrictions. Thus, any qualifying costs incurred from December 21, 2000 to December 31, 2003 are not subject to any geographic restrictions. Costs incurred between August 5, 1997 and December 21, 2000 will be deductible only if they relate to projects in the specified economically-distressed zones.

Some environmental remediation expenditures may also be immediately deductible for another reason under another provision of the tax laws. For example, in 1994 — prior to the enactment of the specific brownfields deduction — the IRS issued guidance that listed a few types of environmental cleanup costs that could be deducted immediately as "ordinary and necessary" business expenses. That list included activities such as excavating contaminated soil, transporting the soil to disposal facilities and back-filling excavated areas with uncontaminated soils. The guidance only applies where such costs were incurred by the party who owned the property and was responsible for the damage in the first place. Costs that are immediately deductible under these rules — or any other provision of the tax law — do not qualify for the brownfields deduction.

Planning Point

If qualified environmental remediation expenditures are deducted pursuant to the federal brownfields tax incentive, some or all of the deductions may have to be recaptured as ordinary income when the property is sold. This means that any gain on the sale of the property will be treated as ordinary income, as opposed to capital gain, to the extent the taxpayer claimed immediate deductions for cleanup costs.

Even considering the recapture requirement, the advantages of taking an immediate deduction for remediation costs will generally provide a greater benefit than adding the costs to the tax basis of the property. However, this analysis typically involves evaluating several factors such as the taxpayer's tax bracket, the timing of the property sale, and current and projected differences between ordinary income and capital gains tax rates.

State Programs

When evaluating a potential brownfields redevelopment project, the availability of state grants and tax incentives should also be considered. A number of states have enacted brownfields tax incentive programs; however, many of these programs do not reach as far as the federal program. For example, Massachusetts enacted a brownfields tax credit program that provides remediation tax credits ranging from 25% to 50% of the cleanup costs. The program is limited to companies that incur remediation costs at sites where the entity seeking the tax credit *did not* cause or contribute to the release of oil or hazardous substances and *did not* own or operate the site at the time of the release. The site must also be located in an "economically-distressed area" and a permanent solution or remedy must comply with the Massachusetts cleanup program requirements.

Other states that have adopted tax incentive programs include Florida (a 33% tax credit of up to $250,000 per site for voluntary brownfields cleanup costs), Illinois (an income tax credit of up to 25% for cleanup costs associated with a sites where the brownfields developer did not cause the contamination), and Ohio (tax credits of up to 10% to 15% of eligible brownfields cleanup costs that may be credited against corporate franchise and state income taxes). Many states have adopted brownfields programs that include not only tax incentives but other financial inducements such as grants and loan programs in order to revitalize distressed communities, boost tax revenue, and create new jobs. ◎

Environmental Update

NSR Reforms

The Bush administration's plans for reforming the "new source review," or "NSR," air permitting regime has come under fire from Senate Democrats and environmentalists. Senator John Edwards (D.-North Carolina) is reportedly prepared to offer an amendment to the 2003 US Environmental Protection Agency appropriations bill that would block the agency from spending any funds on changes it is proposing to the NSR program. The proposed rider to the EPA spending bill reportedly has the backing of the Senate majority leader, Thomas Daschle (D.-South Dakota), and Senator Joseph Lieberman (D.-Connecticut).

The NSR permitting program requires air permits for new and modified major sources of pollution in so-called "nonattainment" areas (areas that do not meet federal ambient air quality standards) and for all major emitters in "attainment" or clean areas.

In August, Senator Edwards and 43 other Senators sent a letter to EPA Administrator Christine Todd Whitman requesting further analysis of the environmental implications of EPA's proposed NSR reform package. While such an inquiry is not expected to have any significant impact on the administration's internal deliberations, the letter sends a signal that there may be sufficient support in the Senate for a rider to the EPA spending bill that would stop the NSR reform effort in its tracks.

There are also reports that many appropriations bills, including the EPA spending bill, may be delayed until after the November elections. The delay may give cover to a number of members of Congress who would like to avoid a vote on a politically-changed environmental issue.

The EPA proposals include five major reforms that are divided into two separate rulemakings. The first four reforms were originally proposed in 1996 by the Clinton Administration, and will be issued as part of a final rule. The first proposal would allow owners of facilities that emit pollutants to make changes to their plants without obtaining a major source NSR permit, provided their emissions do not exceed a specified limit. The second proposal would provide an exemption of up to 10 or 15 years from further NSR review for certain operational changes if a plant has recently installed state-of-the-art emission controls on new or modified emission units pursuant to an NSR permitting review. The third reform is a proposed expansion to other industries of EPA's rule for calculating emission increases for power plants that have begun normal operations. Fourth, the reform package would formalize EPA's policy of excluding pollution control and prevention projects from NSR permitting review where such projects result in a net beneficial impact on the environment.

The fifth reform is intended to clarify what types of activities will qualify as "routine maintenance, repair and replacement." Such activities are exempted from NSR permitting review. EPA is reportedly planning to propose a safe harbor test that would exempt certain maintenance, repair, and replacement activities that are below the cost threshold. This proposal will be issued in a separate proposed rule that will be subject to public notice and comment.

The NSR reform package is currently undergoing a 90-day review by the US Office of Management and Budget, or "OMB," to make sure it complies with federal guidelines that govern the issuance of new rules. After completion of the OMB review, EPA is expected to issue the NSR reform package in late October, or possibly just after this year's elections in November.

Efforts to reform the NSR permitting program began in 1992. The regulated community has long complained that the NSR program discourages the modernization of existing plants, and hampers the siting of new, more efficient, and less-polluting plants. Critics assert that the NSR permitting process is overly time-consuming, burdensome, and costly.

On the state level, Maryland Governor Paris Glendening also recently expressed opposition to the administration's NSR reforms. New Jersey Governor James McGreevey has also threatened legal action to block implementation of the NSR reforms. Both governors are Democrats. Attorneys general from several northeastern states have lined up against the EPA reforms, and are reportedly evaluating strategies to challenge the final NSR rule if and when it is issued. / *continued page 38*

Multi-Pollutant Legislation

The Bush administration's "clear skies initiative" has been translated into comprehensive legislative language and the measure has been introduced in both the Senate and House of Representatives. If enacted, many older power plants would have to be retrofitted with costly pollution control technology or spend significant funds to purchase a sufficient number of allowances to ensure compliance.

Senator Robert Smith (R.-New Hampshire) and Rep. Joseph Barton (R.-Texas) introduced the "Clear Skies Act" at the end of July. The legislation would completely overhaul the current Clean Air Act provisions that apply to power plants and impose significant reduction requirements for emissions of nitrogen oxides, or NO_X, sulfur dioxide, or SO_2, and mercury. The legislation does not call for any cuts in CO_2 emissions from power plants.

The bill would create a mandatory "cap and trade" emission allocation program similar to the federal acid rain program. It would implement the emission reductions in two steps starting with nationwide caps of 4.5 million tons of SO_2 in 2010, 2.1 million tons of NO_X in 2008, and 26 tons of mercury in 2010. These caps would decline in 2018 to 3.0 million tons of SO_2, 1.7 million tons of NO_X, and 15 tons of mercury. Current US emission levels of these pollutants are approximately 11 million tons of SO_2, 5 million tons of NO_X , and 48 tons of mercury. The legislation would also create a "backstop" ceiling price for allowances of \$4,000 for each ton of SO_2 or NO_X and \$2,187.50 for each ounce of mercury. These "backstop" allowances would be available directly from EPA.

Pollution sources that are subject to the new legislation would be exempted from having to comply with other, similar programs such as the "new source review" permitting program and the "best available retrofit technology (or "BART") standards that apply to older sources near national parks and wilderness areas. The new bill, if enacted, overlaps with these existing programs, but is more stringent. Covered sources would also be exempted from certain air toxics standards.

Environmental groups and some member of Congress were quick to criticize the legislation; however, the introduction of the measure is an indication that the Bush administration is serious about attempting to reform the Clean Air Act. There is no time to make any further progress on multi-pollutant legislation this year; Congress is expected to adjourn for the year in early October. However, the issue will probably be a priority next year.

Chemical Security

The issue of security at chemical and power plants is gaining increasing attention within the Bush administration, Congress and the regulated community.

The Bush administration is searching for an approach that will not impose additional burdens on companies that are already moving forward with voluntary enhanced security programs. However, the EPA's plan to release a proposed rule to require enhanced security at chemical plants and other facilities, including some power plants, has reportedly been sidetracked over questions about EPA's statutory authority to issue such a rule.

On the legislative front, Senator Jon Corzine (D.-New Jersey) has introduced a bill that would mandate the preparation of vulnerability assessments and response plans and require that they be submitted to EPA for evaluation and approval. The Corzine bill would apply potentially to the 15,000 facilities that are required currently to prepare and submit risk management plans to EPA under section 112(r) of the Clean Air Act. Section 112(r) applies to accidental releases of hazardous chemicals and not to intentional terrorist acts of sabotage. The risk management plans address a worst-case analysis of potential accidental releases of listed hazardous chemicals. Power plants storing anhydrous ammonia for use in selective catalytic reduction systems are typically subject to the 112(r) requirements.

The provisions of the Corzine bill would potentially require affected plants to prepare detailed vulnerability assessments, which are expected to lead to costly plant upgrades to enhance security, particularly for plants near populations centers. Senator Corzine hopes to offer his bill as an amendment to the homeland security bill that is currently under debate in Congress.

The Bush administration is reportedly working with a bipartisan group of senators to develop an alternative to the Corzine bill. It is also in favor of placing oversight for chemical security within the new Department of Homeland Security instead of with EPA. It is unclear whether Senate Republicans will try to offer an administration-backed alternative to the Corzine approach or work with Senator Corzine to develop a bill that will recognize the voluntary efforts of companies that have already put security improvements in place.

Business groups are becoming actively involved in the process as well. Earlier this year, the American Chemical Council unveiled a voluntary enhanced chemical security measure that all ACC member companies must meet. The ACC requirements call for its 180 member companies to conduct vulnerability assessments at their facilities and to prepare comprehensive release response plans. Approximately 1,000 chemical plants are subject to the voluntary ACC requirements.

Kyoto Protocol

In September, both Russian Prime Minister Mikhail Kasyanov and Canadian Prime Minister Jean Chretien indicated that their respective countries are on target to ratify the Kyoto protocol by the end of the year. If the Russian and Canadian parliaments agree to ratify, the treaty would enter into force by the end of the year.

Ninety four countries had ratified the Kyoto protocol by September 17. Twenty-five of those countries are so-called "Annex I" industrialized countries. The Kyoto protocol will enter into effect after it is ratified by 55 or more countries (including both Annex I and Annex II developing countries) whose emissions represent at least 55% of the carbon dioxide, or CO_2 emissions, from Annex I countries in 1990. So far, countries representing 37.1% of the CO_2 emissions have ratified the protocol. China ratified the treaty in early September. It is classified as an Annex II party even though the country emits approximately 11% of the world's carbon emissions.

Once in effect, the Kyoto protocol will require approximately a 5.2% reduction in greenhouse gas emissions during the first commitment period — 2008 to 2012 — compared to 1990 emission levels. The US, which emitted approximately 36.1% of 1990 CO_2 emissions, has rejected the Kyoto protocol and is instead focusing on voluntary efforts to reduce greenhouse gas emissions by US companies.

Canada's road to ratification of the treaty will probably be rocky. While Canada's prime minister has pledged that the Kyoto protocol will be ratified by Canada, some of the Canadian provinces are raising strong objections. Alberta has reportedly threatened to mount a legal challenge. A significant amount of Canada's energy industry is based in the province of Alberta. Further, Canada continues to press for acceptance of its request for a "clean energy export credit" that would credit Canada for its exports of natural gas and hydroelectric power to the US. This proposal has met strong opposition from the EU countries. It is unclear if the Europeans will ultimately recognize such a credit, particularly if Russia and other Annex I nations ratify the treaty before Canada, thus triggering its implementation.

Air Toxics

The US Environmental Protection Agency has agreed to reduce the time frame for preparing new air permit applications for major air toxic emitters in source categories where EPA has not yet issued standards. Under the 1990 Clean Air Act amendments, EPA was required to issue air toxic standards for all major emitter categories by May 15, 2002 — the so-called "MACT hammer" deadline. Since EPA missed the deadline, the Clean Air Act provided that state and local air permitting agencies would be required to step in and issue case-by-case standards for these major emitters. The air toxic standards require sources to meet maximum achievable control technology, or "MACT," levels.

Knowing that it would miss the MACT hammer deadline for over 60 source categories and subcategories, EPA issued a rule (known as the "112(j) rule") earlier this year that requires each major air toxic emitter in these categories to submit a simple notification to its state or local air permitting agency by May 15, 2002. The notification states that the plant is subject to the rule. EPA gave sources an additional 24 months — to May 15, 2004 — to submit more detailed air toxic permit applications.

Environmentalists challenged EPA's rule, alleging that the agency did not have the authority to extend the application deadline for two years. In August, EPA and environmental groups agreed to settle the case by reducing the application submittal date by 12 months. The new deadline for the expanded applications is May 15, 2003. Facilities that may be subject to the 112(j) air toxics rule include plants with combustion turbines where the plant omits more than 10 tons a year of any one of the 188 listed hazardous air pollutants or over 25 tons of any combination of such pollutants. Electric utility units are currently not yet subject to the 112(j) rule because the deadline for issuing MACT standards for the category has not yet expired. */ continued page 40*

Environmental Update

continued from page 39

Plants subject to the 112(j) rule should begin preparing their applications now since it takes several months to pull together the detailed information on air toxic emissions from the facilities and other information relevant to establishing a case-by-case MACT standard. Failure to file the requisite 112(j) air permit applications would constitute a violation of the Clean Air Act, and penalties could run as high as $27,500 per violation.

Once the detailed permit application is submitted, the state and local air permitting agencies will have 18 months to issue a case-by-case determination. EPA anticipates that it will be able to propose and finalize most, if not all, of the MACT standards by the deadline for issuing case-by-case determinations. Nevertheless, many major air toxic emitters will bear the costs of preparing comprehensive permit applications that are due within eight months.

Brief Updates

The Chicago Climate Exchange, which has been touted as the first voluntary greenhouse gas trading program in the US, is scheduled to initiate trading in early 2003. The exchange has signed up several Fortune 500 companies that are committed to achieving greenhouse gas reductions, including American Electric Power, Calpine, Cinergy, DuPont, Ford Motor Company, International Paper, and PG&E National Energy Group.

In August, the federal land manager for the Mammoth Cave National Park lifted his objections to the proposed Thoroughbred generating station in Kentucky. The Thoroughbred project is a 1,500 megawatt coal-fired plant that will use coal supplied by a nearby mine. The federal land manager removed his objection after reviewing revised air modeling data submitted by the project. Despite the removal of a significant hurdle, the project still faces opposition from several local and national environmental groups, and Indiana has also raised concerns about the plant's cross-border impact.

A July order in *United States of America v. Southern Indiana Gas and Electric Company* recognized that EPA lacked authority to seek civil penalties for air permitting violations more than five years old, and determined that the failure to obtain an NSR permit authorizing the construction of a major modification was a one-time violation. However, the court sided with EPA in agreeing that the agency could seek injunctive relief for an alleged violation of failing to obtain a pre-construction permit.

The New Jersey Department of Environmental Protection has adopted new regulations providing tax credits to power plants and certain industrial facilities that use recycled wastewater known as "gray water" from publicly-owned treatment plants. Companies purchasing equipment to treat gray water for use as makeup water can qualify for up to a 50% credit against the state's corporate business tax and the purchase of the equipment would also be exempted from state sales taxes. ◎

— contributed by Roy Belden in New York.

Chadbourne & Parke LLP
30 Rockefeller Plaza
New York, NY 10112
(212) 408-5100

1200 New Hampshire Ave., NW
Washington, DC 20036
(202) 974-5600

350 South Grand Ave.
Suite 3300
Los Angeles, CA 90071
(213) 892-1000

1100 Louisiana, Suite 3500
Houston, TX 77002
(713) 571-5900

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow, Russian Federation 113054
(7-095) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

Beijing Representative Office
Suite C3, Plaza Business Centre
3rd Floor, North Tower
Beijing Kerry Centre
1 Guang Hua Road
Chao Yang District
Beijing 100020, China
(86-10) 8529-8892

Chadbourne & Parke
a multinational partnership

Regis House
45 King William Street
London EC4R 9AN
(44-20) 7337-8000